D. The Applicant

Document No. D1

ALFRED F. JAHNS
Attorney At Law

April 16, 2009

SENT BY E-MAIL AND U.S. MAIL

Michael Rosauer
Project Manager
California Public Utilities Commission
c/o Dudek
605 Third Street
Encinitas, California 92024

Re: A.07-04-013 – Preliminary Comments on Draft Environmental Impact Report and Request for Additional Information to Facilitate Review For Further Comments

Dear Mr. Rossauer:

The Draft Environmental Impact Report ("Draft EIR") for the proposed Sacramento Natural Gas Storage Project includes, as Appendix B thereto, the System Safety and Risk of Upset Analysis prepared by EDM Services, Inc. ("EDM Assessment"). The purposes of this letter are: (i) to provide preliminary comments by Sacramento Natural Gas Storage, LLC ("SNGS") addressing the EDM Assessment; and (ii) to request that SNGS be provided the spreadsheets and other information showing the calculations underlying the value of the individual and societal risks (injury or fatality) set forth at Sections 6.5.3 and 6.6.3 of Appendix B, respectively, so that SNGS can undertake a fully-informed evaluation of the EDM Assessment.

D1-1

A. Preliminary Comments on EDM Assessment

The EDM Assessment does not include sufficient information to allow a full review of either the individual risk or the societal risk calculations presented. From the information presented, however, we infer that: (i) the retention of the Yolo pipeline segment in the analysis accounts for approximately one-half of the calculated individual risk;[1] (ii) the mischaracterization of certain key engineering design and operating parameters has further compounded the overstatement of risk from the proposed SNGS Project; and (iii) that the EDM Assessment gives no quantified recognition to the reduction in risk that will result from a number of the state-of-the-art mitigation measures that SNGS has voluntarily incorporated into the design of the proposed SNGS Project, as described in SNGS data submissions to the Commission, to further enhance public safety in relation to the proposed SNGS Project.

D1-2

[1] The Yolo pipeline segment was removed from the proposed SNGS Project by the Amendment to Application filed by SNGS on September 12, 2008.

3436 American River Drive, Suite 12 • Sacramento, CA 95864
Tel: (916) 483-5000 • Fax: (916) 483-5002 • E-mail: AJahns@jahnsatlaw.com

In the view of SNGS, as supported by the Probabilistic Risk Assessment submitted by SNGS in this proceeding on July 9, 2008 ("Weatherwax Assessment"), proper adjustments of the EDM Assessment to take into account the design and operating characteristics of the proposed SNGS Project would result in a reduction by approximately a full order of magnitude (i.e. a factor of -10) in the value of the individual risk calculation.[2] Without such adjustments, the Commission and the public will be materially misinformed as to the safety of the proposed SNGS Project.

D1-2 (Cont.)

Failure Rate –

The calculated pipeline incident rate appears to be approximately 4.5 times higher than that calculated in the Weatherwax Assessment (*compare* EDM Assessment at p. B-21 *with* Weatherwax Assessment at Table II-3). We understand the EDM "*opinion of the anticipated frequency*" to have come from the experience data for all pipelines from 2002-2007. These data include pipelines that are decades old and pipelines that have Class 1 through Class 3 construction properties among other more risk prone attributes relative to the proposed SNGS Project. Moreover, the data upon which EDM apparently relied do not take into account the beneficial impacts of the inspection requirements for High Consequences Areas piping, as discussed at p. B-6.

D1-3

Accident Characterization and Consequences Analysis –

The EDM Assessment utilizes incorrect project parameters, which results in an overstatement of both the pressure and duration (*i.e.*, mass release overestimation) in each of a potential failure modes examined, and a corresponding mischaracterization and overstatement of the potential consequences. It appears that the overestimation of consequences was further exacerbated by the fact that many of the mitigation measures recognized to be incorporated into the proposed SNGS Project design (see EDM Assessment at pp. B-51to B-52) are given no quantified risk reduction value in the EDM Assessment.

D1-4

The incorrect parameters that EDM employed include:

- Excessive maximum operating pressure ("MOP") for the compressor to SMUD Line segment (1,000 psig versus 600-700 psig depending upon operating mode).

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[2] The Weatherwax Assessment addressed the Yolo pipeline segment because that Assessment was completed three months prior to the filing of the SNGS Amendment to Application which removed that pipeline element from the proposed SNGS Project design.

- Excessive MOP for the compressor to wellhead segment (1965 psig versus 900-1650 psig depending upon operating mode).
- Incorrect well casing diameter (20" versus 7").
- No adjustment of mass release to reflect the reduction due to the sectionalizing of compressor station to well head pipeline segment.
- Overestimating mass releases in the wellhead to compressor station pipeline by assuming that a puncture would persist for 2 hours and a rupture would persist for 5 minutes prior to termination of operations, when in fact the project is being designed to shut down within 30 seconds of detection of occurrence of a leak or rupture.
- Overestimating mass releases at the wellhead by assuming that a wellhead release would persist for 5 minutes prior to termination of operations, when in fact the project is being designed to shutdown within 30 seconds of detection of occurrence of a wellhead release.
- Employing worst case wind conditions of 20 MPH for a torch fire and only 4.5 MPH for all other postulated accidents.

D1-4 (Cont.)

Individual Risk Significance Criterion –

The EDM analysis asserts that the "generally accepted significance criterion" for individual fatality risks is an annual likelihood of 1 in one million (1:1,000,000 per year). EDM derives this criterion from the California Department of Education ("CDE"), *Guidance Protocol for School Site Pipeline Risk Analysis* (the "Pipeline Risk Analysis Protocol"), which was developed to provide recommended guidance for use by California local educational agencies and the CDE in the preparation and review, respectively, of risk studies conducted for proposed school sites and projects.

In the CDE Pipeline Risk Analysis Protocol, the rate of individual risk ("IR") is defined as follows:

> the annual probability of fatality resulting from a pipeline failure and product release for an individual at the property line or boundary between the usable and occupied portion of a school site and any unoccupied and non-usable portion of the property. The IR probability is determined for a defined level of occupancy (fraction of time at the school site) and outdoor exposure (fraction of time outdoors at the school site). It is assumed that the individual occupies the specified location for which the IR is evaluated.

CDE, Pipeline Risk Analysis Protocol, at p. 2-5. There is no explanation in the EDM Assessment as to how the risk criterion derived from the Pipeline Risk Analysis Protocol applies

D1-5

to the methodology of EDM's calculation of individual risk for the proposed SNGS Project. On the face of the EDM Assessment, it appears that EDM has simply adopted the nominal criterion of 1:1,000,000 without actually applying the methodology for calculating individual exposure risk as set forth in the Pipeline Risk Analysis Protocol.

To the knowledge of SNGS, the Commission has never adopted the CDE Pipeline Risk Analysis Protocol as one of the Commission's risk criteria for pipeline siting. Moreover, in referring to the CDE Pipeline Risk Analysis Protocol, the EDM Assessment does not acknowledge that there are no schools located within the zone of any of the releases modeled by EDM.

D1-5 (Cont.)

B. Additional Information Needed –

Because the EDM Assessment does not display the actual mass releases for each of the quantified releases modeled, it is not possible for SNGS to ascertain how the consequences modeled might have been reduced had the appropriate project design and operating factors been applied. Moreover, because the EDM Assessment does not display the calculations underlying the determination of the IR attributed to the proposed SNGS Facility, it is not possible for SNGS to evaluate the full magnitude of the impacts on that calculation of the utilization of incorrect engineering design and operating parameters. SNGS therefore requests that EDM be directed to provide SNGS with the CANARY mass outputs employed and the spreadsheets displaying the IR calculations, as soon as possible, so that SNGS can undertake a full evaluation of the EDM Assessment in providing comments on the draft EIR.

D1-6

Sincerely yours,

Alfred F. Jahns

Alfred F. Jahns
Attorney for Sacramento Natural Gas Storage, LLC

Document No. D2

SACRAMENTO
Natural Gas Storage

CPCN Application No. 07-04-013

Comments on Draft EIR

8031 Fruitridge Road, Suite B
Sacramento, CA 95820

Phone: (916) 388-2088
Fax: (916) 388-2087



SACRAMENTO
Natural Gas Storage

SACRAMENTO
Natural Gas Storage

8031 Fruitridge Road, Suite B
Sacramento, CA 95820
Phone: (916) 388-2088
Fax: (916) 388-2087

June 19, 2009

VIA FEDERAL EXPRESS

Michael Rosauer
California Public Utilities Commission
c/o Dudek
605 Third Street
Encinitas, CA 92024

Re: Sacramento Natural Gas Storage, LLC – CPCN Application No. 07-04-013
Comments on Draft EIR – State Clearinghouse No. 2007112089

Dear Mr. Rosauer:

Sacramento Natural Gas Storage, LLC ("SNGS" or "Applicant") provides these comments on the Draft Environmental Impact Report ("DEIR") addressing the natural gas storage project for which SNGS has applied for a certificate of public convenience and necessity from the California Public Utilities Commission (the "Commission") in the subject proceeding (the "SNGS Project"). The following comments are organized under six topic headings: (1) Findings of Unavoidable Significant Impacts; (2) Other Environmental Consequences; (3) Project Description; (4) Alternatives; (5) Issues to be Resolved; (6) Miscellaneous Corrections; and (7) Conclusion.

D2-1

I. FINDINGS OF UNAVOIDABLE SIGNIFICANT IMPACTS

The DEIR identifies "significant and unavoidable" impacts in relation to: (a) potential releases of natural gas from the wellhead site and pipeline segments (DEIR, p. ES-41, HAZ-2b); (b) potential migration of natural gas from the Florin Gas Field after re-pressurization (DEIR,

D2-2

p. ES-37, HAZ-2a; and (c) potential nighttime noise from the construction of the wells (DEIR, p. ES-52, N-1). The respective discussions of these impacts in the DEIR should be corrected in numerous material respects; with such correction, SNGS submits that the substantial evidence in the record before the Commission demonstrates that the proposed SNGS Project can be constructed and operated without causing any significant environmental impacts under recognized criteria.

D2-2 (Cont.)

A. Releases of Natural Gas from Wellhead Site and Pipeline Segments

The conclusion in the DEIR that the SNGS Project presents a significant risk of serious injury or fatality from fires or explosions resulting from releases of gas from the pipeline segments and wellhead site rests on a report entitled "System Safety and Risk of Upset" prepared by EDM Services (the "EDM Assessment") set forth as Appendix B to the DEIR. The EDM Assessment is seriously flawed in its mischaracterization of SNGS Project design and operations elements, in its failure to take into account the safety value of certain SNGS Project design and operating parameters, in the methodology (including its assumptions) of its utilization of the CANARY model, and even in its characterization of the risk standard that it attributes to the California Department of Education. Rather than serving the essential function of informing the Commission and the public as to the potential consequences of the SNGS Project in this important area of protection of public safety, the EDM Assessment presents a false and unnecessarily alarming portrayal of safety risks from the SNGS Project.

D2-3

In a preliminary comment letter to the Commission, dated April 16, 2009, SNGS provided the following summary of the mischaracterizations of the SNGS Project contained in the EMD Assessment.

D2-4

- Excessive maximum operating pressure ("MOP") for the compressor to SMUD Line segment (1,000 psig versus 600-700 psig depending upon operating mode).
- Excessive MOP for the compressor to wellhead segment (1965 psig versus 900-1650 psig depending upon operating mode).
- Incorrect well casing diameter (20" versus 7").
- No adjustment of mass release to reflect the reduction due to the sectionalizing of compressor station to well head pipeline segment.
- Overestimating mass releases in the wellhead to compressor station pipeline by assuming that a puncture would persist for 2 hours and a rupture would persist for 5 minutes prior to termination of operations, when in fact the project is being designed to shut down within 30 seconds of detection of occurrence of a leak or rupture.
- Overestimating mass releases at the wellhead by assuming that a wellhead release would persist for 5 minutes prior to termination of operations, when in fact the project is being designed to shutdown within 30 seconds of detection of occurrence of a wellhead release.
- Employing worst case wind conditions of 20 MPH for a torch fire and only 4.5 MPH for all other postulated accidents.

D2-4 (Cont.)
D2-5
D2-6
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D2-9
D2-10

Upon further examination of the EDM Assessment, SNGS has also identified the following critical errors in the EDM modeling methodology.

- The gas release confinement assumptions are incorrect in relation to the SNGS Project setting and result in implausible explosion scenarios, with a consequent serious overstatement of potential harm from SNGS Project operations.
- The gas release mass flow rate settings in the modeling of full bore release scenarios are physically impossible, with a consequent serious overstatement of potential harm from the SNGS Project operations.

D2-11
D2-12

The details and implications of the flaws in the EDM Assessment are provided in the letter reports of Robert K. Weatherwax and John B. Cornwell provided respectively as Appendix 1 and Appendix 2 to this letter. Mr. Weatherwax is the principal author of the report entitled "Probabilistic Risk Assessment [for] Sacramento Natural Gas Storage Project" submitted to the Commission in this proceeding in July 2008 (the "SNGS Risk Assessment"). Mr. Cornwell is a Principal Engineer with Quest Consultants Inc., which designed, owns and licenses the CANARY software model used in the EDM Assessment for the consequences modeling.

D2-13

The EDM Assessment sets forth the conclusion that the "individual risk of serious injury or fatality [from the SNGS Project] is approximately 6.9 x 10^{-6} (EDM Assessment at B-45). According to EDM: "This value is roughly seven times the generally accepted significance criter[ion] of one in one-million per year. As a result, the individual risk from the proposed project is considered significant." (*Id.*)

The EDM Assessment derives its "generally accepted" risk criterion from a publication of the California Department of Education ("CDE") entitled "Guidance Protocol for School Site Pipeline Risk Analysis (the "Pipeline Risk Analysis Protocol"), which was developed to provide recommended guidance for use by California local educational agencies and the CDE in the preparation and review, respectively, of risk studies conducted for proposed school sites and projects.

D2-14

In the CDE Pipeline Risk Analysis Protocol, the rate of individual risk ("IR") is defined as follows:

> **the annual probability of fatality** resulting from a pipeline failure and product release for an individual at the property line or boundary between the usable and occupied portion of a school site and any unoccupied and non-usable portion of the property. The IR probability is determined for a defined level of occupancy (fraction of time at the school site) and outdoor exposure (fraction of time outdoors at the school site). It is assumed that the individual occupies the specified location for which the IR is evaluated.

CDE, Pipeline Risk Analysis Protocol, at p. 2-5 (emphasis added). As stated above, the IR applies only to fatalities. EMD misapplied the Pipeline Risk Analysis Protocol by including

D2-15

incidents of "serious injury" in its individual risk calculation.[1] Moreover, there is no explanation provided in the EDM Assessment, or elsewhere in the DEIR, as to how the risk criterion derived from the Pipeline Risk Analysis Protocol applies to the methodology of EDM's calculation of individual risk for the proposed SNGS Project. The SNGS Project is not essentially a continuous flow pipeline operation; rather, it is a natural gas storage project with intermittent pipeline gas flows during injection and withdrawal operations. The SNGS Risk Assessment properly accounts for the proposed SNGS Project operations; the EDM Assessment does not do so.

D2-15 (Cont.)

D2-16

On the face of the EDM Assessment, it appears that EDM has simply adopted a nominal criterion of 1:1,000,000 without actually applying the methodology for calculating individual exposure risk as set forth in the Pipeline Risk Analysis Protocol. Nonetheless, when EMD's risk calculations are properly adjusted to account for the correct SNGS Project design and operations parameters, the resulting calculated **individual risk of serious injury or fatality is less than one in one million per year (0.903 in one million)**, as shown in the following summary table.

D2-17

The adjustments shown in the following table are explained in Appendix 1 to this letter. As is explained in Appendix 1, even the re-calculated individual risk level remains unrealistically high. Moreover, the adjustments made to correct the over-estimations of individual risk by EDM are properly carried over into a re-quantification of societal risk, which is very closely related to individual risk. Thus, the societal risk level determined by EDM (which EDM concluded to be insignificant) is properly considered to be substantially lower than the already-insignificant levels computed by EDM.

D2-18

[1] This criticism is not intended to imply that SNGS is not concerned with protecting the public from incidents of serious injury in connection with the SNGS Project. To the contrary, the SNGS Risk Assessment does take into account potential serious injury as well as fatality; however, the SNGS Risk Assessment does not express an "individual risk" calculation in relation to the CDE Pipeline Risk Analysis Protocol.

D2-19

ADJUSTMENT DESCRIPTION	ADJUSTMENT MAGNITUDE	RESULTING INDIVIDUAL RISK	REMARKS
EDM IR PREDICTION	0	6.86E-06	Starting Point
DROP SMUD-PGE LINK & ASSOCIATED ACCIDENTS	-1.43E-07	6.71E-06	Both Commercial and Traffic
REQUANTIFY EXPLOSIONS WELLHEAD	-1.49E-06	5.23E-06	Comm, Resid & Power Inn Traffic
REQUANTIFY EXPLOSIONS PIPELINE	-3.53E-07	4.88E-06	Comm, Resid & Traffic- 3 Roads
CHANGE WELL DIAMETERS TO 7" FROM 20" FOR TORCH FIRE	-2.49E-06	2.38E-06	Comm & Power Inn Traffic
REDUCE TORCH FIRE TRAFFIC RISK WITH OP PRESSURE	-6.09E-08	2.32E-06	Part 1:Power Inn, Elder Cr. & Fruitridge Traffic
REDUCE TORCH FIRE TRAFFIC RISK FOR DEEP BURIAL AND REDUCED RATE	-1.77E-07	2.15E-06	Part 2:Power Inn, Elder Cr. & Fruitridge Traffic
FIX SMUD LINK TORCH FIRE RISK FOR OPERATING PRESSURE/RELEASE SIZE	-6.07E-07	1.54E-06	SMUD LINK Torch Fire 210 not 500 feet
REDUCE RES. TORCH FIRE RISK WITH CORRECTED PRESSURE/RELEASE SIZE	-2.70E-08	1.51E-06	Residential Exposure Adjustment
REDUCE COMM TORCH FIRE RISK WITH CORRECTED PRESSURE/RELEASE SIZE	-5.27E-07	9.85E-07	Commercial Exposure Adjustment
ADJUST FAILURE RATE FOR FULL IMPROVEMENTS IN PIPING DEPTH/CLASS	-8.12E-08	**9.03E-07**	Failure rate applies to all pipeline risk

D2-20

B. Potential for Migration of Gas from the Florin Gas Field

The Draft EIR states in the discussion of Impact H-8 as follows:

> There is sufficient evidence to conclude the leakage of gas into the overlying groundwater aquifer is unlikely to occur. However, there is insufficient information to conclude categorically that gas migration to the overlying aquifer would not occur. Therefore it is assumed that there is a low potential that gas could migrate into the aquifer; however, should this migration occur, the gas could contaminate the aquifer. This contamination could be substantial requiring a prolonged period of remediation and impacting the water quality of a ***major potable aquifer.*** This is considered a significant and unavoidable impact (Class I) even with the implementation of Mitigation Measures H-8b and HAZ-2ai, due to the consequence if it were to occur and the difficulty of remediating the contamination.

D2-21

(DEIR, p. D.7-23) (emphasis added). Each element of this significance assessment is in conflict with the substantial evidence that has been presented to the Commission in this proceeding.

The assessment of the possibility of leakage of gas into the overlying aquifer disregards the substantial evidence that the likelihood of gas escapement from that reservoir is so remote as to be negligible. The conclusion that, should gas migration occur, it could impact the water quality of a "major potable aquifer" ignores the multiple stratigraphic barriers -- including two intervening regional saline aquifers separated by a thick shale layer – that exist between the Florin Gas Field and the deepest potable aquifer beginning some 2,400 feet above it. So, too, does the conclusion that a release of natural gas, even with a low probability, has a potential for substantial consequences from fire and explosions due to the project area having high population densities. Finally, the assessment that remediating ground water contamination would be "difficult" overlooks the routine chemical and physical processes in common use to remove natural gas and associated chemicals from water.

D2-21 (Cont.)

D2-22

D2-23

In the following comments, SNGS addresses each of these flaws in the conclusions presented in the Draft EIR with respect to the issue of potential gas migration. At the outset, SNGS notes that in no prior analysis of the proposed development of an underground natural gas storage project has the Commission considered potential escape of injected natural gas from the reservoir to present the potential for significant adverse impacts -- even when its environmental analysis has identified existing uses of overlying aquifers for ground water supplies.[2]

D2-24

[2] D.08-02-035 (Kirby Hills – Phase 2); D.06-03-012 (March 2, 2006) (Kirby Hills); D.02-07-036 (July 17, 2002) (Wild Goose – Expansion); D.00-05-048 (May 18, 2000) (Lodi); D.97-06-091 (June 25, 1997) (Wild Goose).

1. Migration of Natural Gas from the Florin Gas Field

a) Migration through the Cap Rock

The Draft EIR misinterprets the results of the very conservative geomechanical analysis submitted by SNGS in this proceeding with respect to the integrity of the cap rock.[3] As is explained in the comments on the Draft EIR of Golder Associates, attached as Appendix 3 to this letter, under the conditions of cyclic loading that would be produced by the SNGS Project:

> seepage through localized imperfections would require pressures far in excess of those modeled by Ryder Scott assuming a constrained injection pressure of 1,650 psia. More particularly, we explained that no seepage will occur as long as reservoir pressures remain below 2,568 psi. We note that if localized imperfections existed in the Florin Gas Field's cap rock, it would not, given the original field pressure of 1,668 psia, have retained gas for several million years and during production.

On the basis of the injection simulations set forth in Ryder Scott Company (2008) (as referenced in the DEIR),[4] SNGS has designed its injection operations not to exceed 1,650 psia of injection pressure. SNGS requests that Table D.6-1 of the DEIR be revised to incorporate this design constraint as an "Applicant Proposed Measure."

D2-25

Addressing the remote risk of fracturing of the cap rock from a seismic event, the Golder Associates comments (Appendix 3) explain that the magnitude of earthquake (M 8.8) on the fault closest to the SNGS Project that would be necessary to fracture the cap rock has a theoretical expected annual risk of occurrence of **1 in 2 billion**. Moreover, this probability should be

D2-26

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[3] Golder Associates (2008) (as referenced in the DEIR).

[4] In the DEIR, at p. D.6-45, the reference to the Ryder Scott work identifies a May 16, 2008 letter from Ryder Scott to Jim Fossum, SNGS. In the context of the discussion in Section D.6 of the Ryder Scott analyses, it is clear that the reference is intended to be to the letter from Ryder Scott to Jim Fossum, SNGS, dated June 30, 2008. The references by SNGS in this comment letter to "Ryder Scott (2008)" are to the June 30, 2008 letter.

D2-25 (Cont.)

considered an upper bound because, as the Golder Associates comments explain, such a large magnitude earthquake is essentially impossible.

D2-26 (Cont.)

Concerning the possibility of diffusion through the cap rock, the DEIR incorrectly characterizes the estimate in Golder Associates 2008 to be that permeation would occur over a period of thousands of years. (DEIR, pp. D.6-24-D.6-25.) In fact, Golder stated that such "leakage may occur on a geologic time scale (**millions of years**)" rather than over thousands of years. (Golder Associates 2008, p. 31.) (Emphasis added.)

D2-27

SNGS agrees that laboratory tests should be performed on an intact rock core sample taken from the shale cap rock. SNGS proposes that the protocols for such testing set for in the comments of Golder Associates (Appendix 3) be adopted by the Commission. SNGS further proposes that the sonic-sidewall scanning recommended by Golder Associates also be required by the Commission.

D2-28

b) Migration Around the Cap Rock

The DEIR states that: "Neither the bottom of the reservoir nor the sides of the reservoir has been well defined in detail, especially since drilling and core sampling has not been conducted at the well field perimeter. Therefore, it is not known whether gas would seep in this area under pressures exceeding original reservoir pressure." (DEIR, p. D.6-25.) This conclusion ignores the SNGS Project design parameters that will limit injection pressures to a maximum of 1,650 psi and will limit the total volume of injected gas to 7.5 bcf, which is significantly less than the less than the total approximately of 8.28 bcf produced from the reservoir. According to the analysis of Ryder Scott set forth in Appendix 4, these operating

D2-29

restrictions will ensure that no gas will escape through the bottom or around the edges of the reservoir as a result of the SNGS Project.

D2-29 (Cont.)

2. **Stratigraphy Overlying the Florin Gas Field**

The comments of Ryder Scott in Appendix 4 also explain the stratigraphy overlying the Florin Gas Field. As can be seen in the figure included therein, the Starkley Formation, consisting of an approximately 1,100-foot-thick sequence of fluvial-deltaic sands, overlies the cap rock that seals for Florin Gas Field. The Starkley Formation is in turn overlain and capped by an impermeable shale layer. In the highly remote event of escape of natural gas from the Florin Gas Field through the overlying cap rock, the most likely preferential migration pathway would be lateral movement within the saline groundwater contained in the Starkey sands rather vertical movement toward the surface. In the highly remote event of escape of natural gas laterally from the Florin Gas Field, the most likely preferential migration pathway would be lateral movement within the Winters Formation. The basis for these conclusions is provided in the comments of Ryder Scott (Appendix 4) and in the comments of ETIC Engineering, Inc. (Appendix 6).

D2-30

Ryder Scott (Appendix 5) has also explained how any migration of natural gas from the Florin Gas Field can readily be detected through appropriate monitoring within the Winters Formation and in the aquifer contained in the overlying Starkey Formation (consistent with the mitigation requirements in the DEIR, HAZ-2*ai*).

D2-31

3. Remediation of Groundwater Contamination

The conclusion in the DEIR that the risk of natural gas migration from the reservoir poses a significant impact rests in part on the assertion that remediation of "contaminated" groundwater would be "difficult." (DEIR, p. D.7-23). As the thorough analysis of ETIC Engineering (Appendix 6) demonstrates, in the extremely remote event that migration of natural gas from the Florin Gas Field were to adversely impact any beneficial uses of groundwater, there are common, effective technologies that could readily be employed to remediate the "contamination."[5]

D2-32

4. Conclusion

Taking into account the analyses in Golder Associates (2008) and Ryder Scott (2008), Dr. Robert Mannon reached the following conclusions:

D2-33

1. The use of the Florin Gas Field as a gas storage reservoir is confirmed as suitable from the standpoint of safety.

2. The likelihood of gas migrating through the Florin gas cap is nil. Correspondingly, there will be no contamination of the fresh water sands by migrating gas from the Florin reservoir or migration of gas to the surface.

D2-34

3. In the environment of the Florin reservoir, it will be possible to monitor and control the movement of fluids within the reservoir to prevent gas migration beyond the field limits.

D2-35

4. An investigation of the abandoned well records indicates the proper steps were taken in the well abandonments and that they are safe.

D2-36

5. Consultations with those responsible for the design of the new wells indicate the application of appropriate design criteria and more than adequate redundancy to provide for safe operations.

D2-37

[5] As is noted by ETIC in Appendix 6, at p. 3, there are no health effects from ingesting water in which methane gas is dissolved. Methane gas only potentially becomes harmful as a safety risk if it escapes from water (at concentrations greater than 28 milligrams per liter [mg/L]) into a confined space.

D2-38

(Mannon 2008 (as referenced in the DEIR), pp. 11-12.) Other experts have reached similar conclusions in general concerning the feasibility of safe operations of natural gas storage operations in produced natural gas fields, even in urban settings.[6]

D2-39

Dr. Mannon also carefully explained why gas migration problems that occurred at El Segundo, Castaic Hills, and Montebello (referenced at page D.6-23 of the DEIR) will not be experienced at the Florin Gas Field. At Montebello, which was discovered in 1917, hundreds of wells were drilled without proper oversight or documentation, and faulty completion methods undoubtedly resulted in serious surface leaks. The problems at El Segundo resulted from the operator injecting Liquid Petroleum Gas into three different water sands at high injection and withdrawal rates. Operators injecting LPG, as opposed to natural gas, have no control over its placement in the reservoir. As a result, Dr. Mannon cautioned that "LPG storage should never be done near populated areas, if at all." (Mannon 2008 at p. 5.) Finally, Dr. Mannon explained that gas migration problems experienced at the Castaic Hill Oil Fields resulted from the "considerable faulting" in the area, which included faults that extended to the surface, which made the field a poor candidate for gas storage. (*Id.*) (As recognized in the DEIR, there are no faults located in or near the Florin Gas Field.) Dr. Mannon's report thus established that the causes of gas migration at El Segundo, Castaic Hills, and Montebello have no application to the Florin Gas Field.

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[6] A.E. Gurevich, B.L. Endres, J.O. Robertson, Jr, and G.V. Chilingar, *Journal of Petroleum Science and Engineering*, 9 (1993) Page 227 (in which the G.V. Chilingar stated: "The managing editor, who is also the co-author of this paper, firmly believes that underground gas storage and oil and gas production in urban areas can be conducted safely if proper procedures are followed . . . .") (Appendix 7); D. J. Evans, *An Appraisal of Underground Gas Storage Technologies and Incidents, for the Development of Risk Assessment Methodology* (HSE Research Report RR605 – 2008) (Evans 2008) (Appendix 8).

D2-39 (Cont.)

Evans 2008 confirms Dr. Mannon's analysis regarding the problems at Montebello, stating that many of the wells there "were drilled before today's rigorous drilling and completion standards were implemented or applied[.]" (Evans 2008 at p. 105.) Evans 2008 also states that faulting at Castaic Hills and El Segundo has been recognized as responsible, at least in part, for gas migration at those fields. (*Id.* at pp. 104, 179.)

D2-41

SNGS submits that the discussion in the DEIR provides no credible basis for attaching a significance finding to the speculation that migration of gas from the Florin Gas Field either could impact the water quality of a major potable aquifer or has a meaningful potential for substantial consequences from fire and explosions due to the project area having high population densities. The substantial evidence in the administrative record instead supports the conclusions that; (a) the likelihood of the occurrence of migration of natural gas from the Florin Gas Field is so extremely remote as to be insignificant under CEQA; and (b) the likelihood of the occurrence of any substantial adverse environmental impact in the event of such migration is likewise so extremely remote as to be insignificant under CEQA.

D2-42

C. Noise

The DEIR concludes that nighttime noise from the construction of the wells may result in a significant and unavoidable impact. (DEIR at pp. ES-52, D.9-10.) As SNGS explains in the following discussion, this conclusion is inconsistent with empirical data that have been reported with respect to drilling operations in urban settings.

D2-43

The DEIR also incorrectly states that SNGS did not propose any measures to mitigate potential impacts from noise. In fact, SNGS proposed such measures in its Proponent's

D2-44

Environmental Assessment (MM NOI-1, MM NOI-2 and MM NOI-3). SNGS requests that the DEIR be corrected to reflect these Applicant Proposed Measures.

D2-44 (Cont.)

1. Distance for Noise Attenuation

The Draft EIR incorrectly asserts that: "The closest sensitive noise receptors are located in the vicinity of the proposed wellhead site and consist of residential units located approximately 200 feet across Power Inn Road." (DEIR at p. D9-8.) In fact, the western boundary of the real estate parcel that will house the wellhead site is more than 100 feet from the nearest residential unit, and the drilling rig will be located more than 350 feet farther east and away from the residences. Therefore, the distance from the drilling operation, which will be the primary noise generator at the wellhead site, will be approximately 450 feet from the nearest residence, i.e., the closest sensitive noise receptor.

D2-45

2. Sound Levels Generated by the Drilling Construction Operation

The Draft EIR cites a standard reference document of sound data contained in a 1995 Federal Transit Administration standard for noise levels generated by typical construction equipment used primarily in road-building. (DEIR, Table D.9-5.) Many of the equipment items cited are common to both general construction and site preparation of a wellhead site. Noise levels for the items of equipment that will be used for site preparation on the SNGS wellhead site ranged from 72 to 88 dBA at a distance of 50 feet from the source. As would be expected, no standard noise levels are provided for well drilling operations.

While it would be to the Applicant's benefit to accept these levels of noise as the starting point for noise levels to be experienced at the nearest sensitive receptor, i.e., the nearest

D2-46

residence, SNGS suggests that more pertinent data are available in energy industry documents that specifically address drilling operation noise impacts in urban areas. One of the most applicable documents found in the literature includes actual noise readings recorded at an urban drilling operation and at various distances up to 500 feet from the drilling rig.

D2-46 (Cont.)

Table #2 Typical Rig Operation Noise Levels

Typical Equipment	dbA at Source	dbA 200 ft	dbA 300 ft	dbA 500 ft
Dozer	85	49	31	0
Backhoe	98	62	44	7
Generator	89	53	35	0
Air Compressor	101	65	47	10
Drilling Rig	98	62	44	7

Datra Source:
Conrad Sansoucie, Environmental Affairs Manager, CNR LLC

Although the study cites a 101 dBA sound level for a "compressor," that noise source is irrelevant for the purposes of the SNGS Project, which will not have a compressor at the wellhead site. The pertinent maximum sound readings recorded by the study are thus those documented at the drill rig, which were 98 dBA. Given that SNGS has committed to using an electric drive drilling rig, the reported value may be greater than what will be produced by the SNGS drilling rig. SNGS suggests that the reported values therefore provide a reasonable, conservative basis of estimate for the sound levels that will be produced at the SNGS drill rig and should be used as the starting point for calculating maximum noise levels at the nearest sensitive receptor. The study including these data is published in Society of Petroleum Engineers Paper 92647, "Urban Operations: Drilling and Completing a Gas Well on a Downtown University Campus", as presented at the SPE/IADC Drilling Conference held in Amsterdam, The Netherlands, 23-25 February 2005 (provided as Appendix 9 to this letter).

D2-47

The Draft EIR states without justification or reference that "Construction noise in a well-defined area typically attenuates at approximately 6 dBA per doubling distance." (DEIR at p. D.9-8.). SNGS submits that the empirical data reported in the study provided in Appendix 9 provide a more substantial basis for evaluating the potential significance of nighttime noises from the SNGS Project well drilling operations. D2-48

3. Sound Levels at Nearest Sensitive Receptor

As shown above, the actual test results for a drilling operation similar to the SNGS Project, conducted in a similarly open, but urban area, show the attenuated noise level to be 44 dBA at 300 feet from the sound source, and 7 dBA at 500 foot distance. Simple extrapolation indicates that at a distance of 450 feet from the drilling operation, which would be the location of the closest sensitive receptor, the sound levels would be approximately 17 dBA. This compliance with nighttime noise standard of the Sacramento City of Sacramento is achieved even without the Applicant Proposed Measure of a temporary sound barrier. D2-49

4. Reduction Achieved by Temporary Sound Barrier

The Draft EIR estimates that installation of a temporary sound barrier would result in a 5 to 10 dBA attenuation of noise. According to a sound consultant's Acoustical Report of testing of sound barriers, current test results of sound attenuation with 20-foot high temporary sound barrier frequently reach 17-20 dBA sound reductions.[7] Actual test results for a lower 10-foot tall D2-50

[7] Barnett Shale Compressor Station, Summary Acoustical Report, March 28, 2008 (attached as Appendix 10).

barrier with a 1-foot opening along the bottom indicated from 7.5 dBA to 12 dBA of sound attenuation.[8]

D2-50 (Cont.)

5. Conclusion

The analysis of potential nighttime noise levels in the DEIR should be revised to take into account the correct distance of the drilling operation/wellhead location from the nearest sensitive receptor, to use empirical data recorded and published for noise levels generated by a drilling operation similar to that SNGS will employ, and use the noise attenuation levels actually observed at specific distances from the drilling operation during the study cited. With those adjustments, the substantial evidence shows that there will not be any significant noise impacts from the SNGS Project during nighttime well drilling construction.

D2-51

II. OTHER ENVIRONMENTAL IMPACTS

A. Population and Housing

SNGS offers the following comments on Section D.10 – Population and Housing, including references to Environmental Justice.

D2-52

1. Supplementing the demographic information set forth in Table, D.10-1 and D.10-2, SNGS has ascertained the demographics of the ownership of the 287 acres overlying the Florin Field. These are set forth in the following table:

[8] Noise Level Measurements Sound Fighter Barrier Wall BAE Systems, Inc., April 7, 2009 (attached as Appendix 11).

D2-50 (Cont.)

Owner Ethnicity	Total Parcels	Percentage of Total
Asian	234	31%
Anglo	201	27%
African American	154	20%
Hispanic	119	16%
Other	45	6%
Totals	**753**	**100%**
On Market	7	
City of Sacramento	11	
Grand Total	**771**	

D2-52 (Cont.)

Further, SNGS has compared the project acceptance data (as shown by executed storage leases of surface lands within the 287 acre area) by the same demographic breakdown as follows:

Owner Ethnicity	Total Parcels	Total Leased	Percentage Leased
Asian	234	178	76%
Anglo	201	157	78%
African American	154	92	60%
Hispanic	119	88	74%
Other	45	38	84%

D2-53

The foregoing information is based on the voluntary execution by some 822 persons holding title to 553 parcels out of a total of 771 parcels for a project acceptance rate of 72%. It is noteworthy that of the parcels remaining to be leased the SNGS internal data show the following:

- 11 parcels are owned by the City of Sacramento and the Sacramento Housing and Redevelopment Agency and have been the subject of negotiations with City Staff (including the City's engagement of its independent appraiser to validate the fairness of the SNGS offer) but cannot be completed until completion of the CEQA proceedings and overall approval by the City Council of related project issues.
- 34 parcels have been foreclosed upon or are the subject of foreclosure proceedings.
- 7 parcels are on the market.
- The owners of 5 parcels have not been located.
- The owners of 126 parcels are undecided or waiting for additional information or events, including in some cases a desire for higher compensation than offered by SNGS.
- The owners of 69 parcels have refused to execute storage leases for a variety of reasons.

D2-53 (Cont.)

2. SNGS submits that the extremely high project acceptance rate by the people in the position to lease storage rights is attributable to a number of factors, including:

(a) The highly advantageous SNGS rental offer ("Offer") which substantially exceeds both the independent appraisal made by Harold W. Bertholf, Inc. at the request of SNGS[9] and a more recent market rent survey by Integra Realty Resources

D2-54

[9] Mr. Bertholf attached a copy of his appraisal as an exhibit to the testimony he submitted in the CPCN portion of this proceeding. (SNGS-14, Exhs. A&B.) Mr. Bertholf's appraisal is compared to SNGS' offer in the direct testimony of Jim Fossum and Don Russell, which were also submitted in the CPCN portion of this proceeding. (SNGS-8 at pp. 8-9, Response to Question 17; SNGS-11 at p. 5, Response to Question 20.) If a further copy of this voluminous appraisal is needed, please let us know.

at the request of the City of Sacramento as to the City lands located in the center of the residential portion of the field. A comparative statement of total projected rental per acre as determined by each appraiser vs. the SNGS offer for the first 15 years of the lease term is set forth as follows:

Source	15 years of rental per acre
Bertholf (SNGS):	$39,540
Integra (City):	$31,315
SNGS Offer:	**$50,160**

D2-54 (Cont.)

(b) For essential economic fairness, it is the policy of SNGS to treat all landowners, including the City, the residential, commercial and industrial owners on the same basis and without any price discrimination.[10] Accordingly, SNGS's Offer to all landowners includes a signing bonus of $1,000 per acre, but not less than $500 per parcel (a typical residential parcel occupies a site of 0.18 to 0.20 acre), and, after the project goes on-line, a minimum annual rental of $1,000 per acre, but not less than $500 per parcel against a percentage rent equal to the parcel's pro rata share of 4% of annual gross revenues generated by the project, whichever is greater.[11] Based on estimated annual gross revenues of approximately $17,600,000, the project would generate a total annual percentage rent of $704,000, or approximately $2450 per acre of new cash flowing into the immediate neighborhood. According to SNGS appraisal witness, Arthur Gimmy, capitalization of this cash flow would produce a one-time

D2-55

[10] *See* Appendix 12 at p. 8, Response to Question 17.
[11] Appendix 13 at p. 5, Response to Question 20.

value enhancement of $7,353 per residence, $36,029 per acre and $10,350,000 for the 287 acre field.[12]

D2-55 (Cont.)

(c) The lease covenants provide substantial benefits and protection to the landowners, including a 4% annual CPI rental adjustment, a broad form indemnity against damages, liability insurance, payment of property taxes on the storage rights, periodic payment of a royalty for any pre-existing gas that might be produced by SNGS, and a seven day "cooling off period" for landowners who decide to walk away from the deal.[13]

D2-56

(d) As there are a number of residents in the area who live adjacent to the gas storage reservoir but not over it (and are therefore not eligible to receive storage rights lease payments), SNGS has sponsored and will fund a non-profit community foundation ("Our Neighborhood Partnership") to support projects or activities that will benefit the surrounding neighborhoods. SNGS has pledged annual funding of .25% of annual gross revenues generated by the Project.[14] This is expected to generate up to $44,000 per year and will be paid over to the City's non-profit corporation called "Gifts to Share" for distribution as determined by the board of directors of Our Neighborhood Partnership.[15] Our Neighborhood Partnership is now independent of SNGS and is governed by a seven member Board elected by vote of the membership.

D2-57

[12] *See* Appendix 14 at p. 14, Response to Questions 38-40.
[13] *See* Appendix 12 at pp. 8-9, Response to Question 17 and Exhibit I attached thereto.
[14] *See id.* at p. 9.
[15] *See id.*, Exh. J attached thereto.

(e) The SNGS project will provide high-value construction and operational jobs for residents and others at this time of economic distress and high unemployment, and SNGS has entered into a project labor agreement with Sacramento-Sierra's Building and Construction Trades Council to ensure that the project is constructed with union labor.[16]

D2-58

(f) According to the testimony and report of Dr. Robert Fountain, the project will bring economic benefits to the City of almost $78,000,000 during the construction phase of the project and almost $25,000,000 annually thereafter during operations.[17]

D2-59

(g) According to the expert testimony and report of John Schleimer of Market Perspectives, his investigation of a number of residential communities located above or near gas storage facilities demonstrated no loss of market value in the residences immediately above such facilities versus residences elsewhere in the area.[18] These facilities are located in St. Louis, Missouri; Houston, Texas; Goleta, California and Playa del Rey, California. The expert testimony of Arthur Gimmy also found that no loss in residential market value will occur and, as stated above, found that an actual enhancement of value will result from the new stream of rental income.[19] This testimony negates the unsubstantiated opinions of several project opponents who have followed the AGENA line in asserting that their home values would be affected adversely. The Schleimer and Gimmy testimonies strongly support the conclusion of

D2-60

[16] *See* Appendix 12. Exh. K attached thereto.
[17] *See* Appendix 15 at pp. 4-5, Response to Question 14 and Exhibit B attached thereto.
[18] SNGS-18 at pp 1-3, Response to Questions 8-16. If a further copy of this voluminous report is needed, please let us know.
[19] Appendix 14 at pp. 13-14, Response to Questions 36-40.

the Draft EIR at Impact P-5 (p.D.10-9) that "no potential significant impact resulting in urban decay or degradation from the project is anticipated". D2-60 (Cont.)

(h) Similarly, opposition claims that the availability and cost of homeowner insurance would be adversely affected was negated by the testimony of insurance actuary Shawna Ackerman whose expert opinion was that no such result would occur.[20] D2-61

(i) The project will benefit the neighborhood and all of the Sacramento area, with a land use that, as confirmed in the Draft EIR, is 100% in accordance with the City's General Plan. No above-ground facilities or operations will be located in the residential area west of Power Inn Road. All of the above-ground facilities are proposed to be located east of Power Inn Road on sites zoned for industrial development. D2-62

(j) Sacramento Municipal Utility District ("SMUD") is the essential supplier of electric energy in the neighborhood and in Sacramento generally. As set forth by SMUD in its February 25, 2008 letter to PUC Commissioner Timothy Alan Simon and in the testimony of Barry Brunelle, the SNGS project will offer the following benefits to SMUD and its ratepayers: D2-63

- Provide some 30 days of backup and emergency gas supply at a critical location on the SMUD pipeline. At this location it will supply gas to SMUD's

[20] Appendix 16 at pp. 2-3, Response to Questions 6-13.

gas-fired power plants in the event of any upstream interruption or curtailment.[21]

- Permit the stockpiling of gas when lower cost supply is available and thereby avoid the need to purchase supply when gas is in high demand at higher prices.[22]
- Provide gas-powered generation to back up other sources of power.[23]
- Relieve SMUD of any development or operating risks.[24]

The foregoing measures and benefits were not taken into account in Draft EIR Section D.10.3.2 "Applicant-Proposed Measures" which stated that:

> "There are no applicant proposed measures (APMs) proposed by SNGS, LLC for impacts related to population and housing. However, the applicant will pay a royalty to each property owner living above the Florin Gas Field during the duration of the Proposed Project." [25]

Indeed, the foregoing measures and benefits amply demonstrate that the project does afford many, many APM's as well as a high degree of environmental justice for this community, even putting aside the fact that the location of the project is driven not by socio-economic factors but

D2-63 (Cont.)

[21] *See* Appendix 17; Appendix 18 at pp. 4-5, Response to Question 15.
[22] Appendix 18 at pp. 3-4, Response to Questions 12-14.
[23] Appendix 17; Appendix 18 at p. 5, Response to Question 18.
[24] Appendix 12 at p. 8, Response to Question 17.
[25] The reference to the payment of a royalty in the DEIR should be corrected and further explained. SNGS will make a storage rights lease rental payment to each owner of property overlying the storage reservoir for the duration of the SNGS Project. In addition, if SNGS removes any native natural gas that exists in Florin Gas Field at the commencement of the SNGS storage operations, SNGS will pay the mineral rights owners a royalty payment for that that removal.

D2-64

rather by the geological location of the partially depleted Florin Gas Field. Accordingly, SNGS does endorse the ultimate findings of the Draft EIR at D.10-8 that the project "would not disproportionately degrade minority or low-income communities" and "would result in equity of economic benefits in low-income/minority communities."

D2-63 (Cont.)

B. Wetlands

Mitigation Measures B-3a and B-6 concerning potential wetlands impacts should acknowledge the fact that the project will comply with the Army Corps' policy to ensure no net loss of wetlands or other waters of the United States, and their associated functions and values. As noted in the Draft EIR, where wetlands cannot be avoided, the acreage of jurisdictional wetlands affected shall be replaced so as to ensure no net loss of functions and values, in accordance with Army Corps regulations. The final compensatory ratio shall be determined in coordination with the resources agencies and specified in the regulatory permits issued. Habitat restoration, rehabilitation and/or replacement, either directly or through an established mitigation bank, shall be at a location and shall be conducted by feasible methods agreeable to the Army Corps or other applicable agencies, depending on which agency has permitting authority. Methods for designing and implementing restored, rehabilitated and/or replacement wetlands shall be determined by qualified restoration ecologists to ensure that the desired results are achievable.

D2-65

C. Greenhouse Gas Emissions

The Draft EIR's discussion of greenhouse gas emissions in relation to global climate change should acknowledge that the project will advance the objectives of AB 32 by encouraging use of natural gas as a clean fuel replacement for liquid or solid fuels, as encouraged

D2-66

by air quality plans in California generally and in the SVAB in particular. Because the project would be designed as a natural gas storage resource for the area, it would support the reduction of fuels that emit a higher concentration of CO_2. This would support the reduction goals of AB 32.

D2-66 (Cont.)

The discussion should further acknowledge that the project will use emission control technologies that will reduce its contribution to CO_2 emissions during construction as well as in operation. The project will use electric drill rigs to construct the wells at the wellhead site rather than diesel or gas-powered equipment, which will reduce CO_2 emissions by approximately 46 tons (the estimated amount that would be produced by gas-powered drills). In addition, the compressor station will use electric-powered compressors. A gas-powered compressor station, with equivalent 3,500 horsepower motors, would produce approximately 1,440 tons of CO_2 per year. By designing construction and operation of the project to use electric-powered equipment in this manner, the amount of CO_2 emissions associated with the project has been reduced to a less-than-significant level.

D2-67

III. PROJECT DESCRIPTION

The project description section of the DEIR includes factual inaccuracies and/or omits information regarding the following subjects: the estimated surface area overlying the portion of the Florin Gas Field proposed to be used by SNGS for storage operations; the pressures at which the proposed project will be operated by SNGS; the length of Pipeline Segment 1; certain applicant proposed measures relevant to the project's safe operation; the volume of gas produced from the Florin Gas Field; and the amount of gas left in place after production ceased. The errors and omissions on these subjects are detailed below.

D2-68

A. Estimated Surface Area Overlying Portion of Florin Gas Field to be Utilized for SNGS Project

The DEIR's assertion that the surface area overlying the Florin Gas Field totals 379 acres overlooks: (1) the evolution of the information provided to the Commission to characterize the Field; and (2) the fact that SNGS does not propose to utilize the full volume of the Field for the proposed storage operations.[26]

D2-69

In Ryder Scott 2008, Ryder Scott delineated the Field's surface boundaries on the basis of modeling supported by a team of highly qualified professionals that included geologists and petroleum engineers. That team's methodology in developing the Field's surface boundaries is described in the testimony of Bruce Palmer and George Dames. (*See* Appendix 19 at pp. 3-4, 7-12, 18-19, Responses to Questions 10-12, 32-62, 76-80; Appendix 20 at pp. 3-4, Response to Questions 14-20.) As detailed in that testimony, Ryder Scott developed a three-dimensional model of the Florin Field based on detailed information compiled during production. (*See* Appendix 19 at pp. 7-12, 18-19, Responses to Questions 32-62, 76-80.) Ryder Scott refined and re-calibrated the model until its simulations of the Field closely matched the Field's behavior as shown in the Field's production history records. (*Id*, at pp. 7, 11, and 15, Response to Questions 32, 58, and 68-69.)

D2-70

[26] SNGS acknowledges that it may have contributed to this disconnect by not specifically calling out to the Commission's attention the refined depiction of the reservoir area proposed to be used for its storage operations presented in Ryder Scott 2008, which SNGS submitted to the Commission on July 9, 2008, in support of the development of the DEIR. The issue of the size of the portion of the reservoir proposed to be used by SNGS for its storage operations was addressed in sharp focus during the subsequent evidentiary hearings in this proceeding, as the following comments in the text describe.

D2-71

As of August 31, 2008, Ryder Scott had devoted over 2000 hours on geology and engineering for the proposed project. (Appendix 19 at p. 4, Response to Question 13.) Ryder Scott's delineation of the Florin Field's surface boundaries thus reflects the application of the best information available and methodologies generally accepted among gas and petroleum engineers. The DEIR should therefore list the amount of land included within the Ryder Scott boundaries, as conservatively adjusted by SNGS, which totals 287 acres. (*See* Exhibit Appendix 19 at pp. 18-19, Response to Questions 76-80; Appendix 12 at pp. 6-7, Response to Questions 14-15.) The map showing the surface boundaries of the Florin Field delineated by Ryder Scott was entered into evidence in the CPCN portion of this proceeding. (*See* Appendix 12 at p. 6, Response to Question 14, Exhibit D; Appendix 19 at p. 18, Response to Questions 77-78, and Exhibit E attached thereto.)

D2-72

That map should be included in the Final EIR, and Figure B-2 should be corrected to show the non-productive zone Ryder Scott identified through its thorough analysis of the Field.[27] In addition, the gas field location estimated by DOGGR should be removed because DOGGR delineated those boundaries for illustrative purposes only based upon the location of productive wells, rather than on a thorough analysis of the Field. It is the understanding of SNGS that DOGGR will confirm this characterization of its map in its comments on the DEIR.

D2-73

The DEIR refers, at page B-2, in footnote 1, to a "debate" between Ryder Scott and Dr. Robertson regarding the size of the Florin Gas Field. This assertion is inaccurate. In order for there to be a "debate" among experts, there must be substantial evidence to support the opinions

D2-74

[27] Dames explained the delineation of the unproductive zone as showing an "erosional reservoir termination" indicated by the lack of sand in the log of the Venada Anderson well and the seismic data covering this area. (*See* Appendix 20 at pp. 3, 6, Responses to Questions 14 and 24.)

D2-75

of both experts. *See Citizens' Com. to Save Our Vill. v. City of Claremont*, 37 Cal. App. 4th 1157, 1171 (1995) ("Argument, speculation, unsubstantiated opinion or narrative, evidence which is clearly inaccurate or erroneous, . . . , is not substantial evidence. Substantial evidence shall include facts reasonable assumptions predicated upon facts and expert opinion supported by facts.") (quoting Cal. Pub. Resources Code, § 21080, subd. (e)); *Lucas Valley Homeowners Ass'n v. County of Marin*, 233 Cal. App. 3d 130, 157 (1991) (Board could discount "evidence" by speakers who were not qualified to render an expert opinion, and who omitted relevant factual material);

D2-74 (Cont.)

Here, there is no substantial evidence supporting Dr. Robertson's opinions regarding the size of the Florin Gas Field. The expert testimony submitted by SNGS overwhelmingly demonstrates that Dr. Robertson's analysis was so fundamentally flawed that his opinions cannot be given any weight. The fatal errors in Dr. Robertson's analysis are detailed in the testimony of Bruce Palmer, George Dames, Eric Hadsell, and Robert Mannon. The testimony of these four experts unequivocally established that Dr. Robertson made fundamental errors by, among other things:

D2-75

- Stating that natural gas has a much higher viscosity than oil, when, as shown by basic petroleum engineering textbooks, the opposite is true. (*See* Appendix 19 at pp. 16-17, Response to Question 72.)

D2-76

- Asserting that the Florin Gas Field's gas sands are only 10 feet deep on average, when the gamma ray logs generated during production very clearly show depths ranging from 10 to 50 feet, with an average depth of 31 feet. (*See* Appendix 21 at pp. 2-3, Response to Questions 11-12, 16.)

D2-77

- Asserting that the well perforations located at the upper reaches of the gas sands supposedly confirmed the depth of such sands, when in fact it is common practice among natural gas production companies to perforate at the top of the gas sands in order to minimize the intrusion of water during production. (*See* Appendix 21 at pp. 2-3, Response to Questions 12-14; *see also* Appendix 20 at pp. 4-5, Response to Question 21).

D2-78

- Asserting that shale "stringers" located in the Florin Gas Field's gas sands prevented vertical communication within such sands, when well logs for the Field do *not* show the lateral continuity that would be needed in order for the Field's shale bodies to act as a barrier to gas movement below the cap rock. (*See* Appendix 21 at pp. 3, Response to Questions 14; *see also* Appendix 19 at p. 15 , Response to Question 67.) **D2-79**
- Relying on a book discussing recovery factors for carbonate reservoirs that every graduate of a petroleum engineering program at any accredited California college or university would know was inapplicable to the Florin Gas Field. (*See* Appendix 22 at pp. 3-4, Response To Questions 4-17; *see also* Appendix 19 at p. 17, Response to Question 74.) **D2-80**
- Providing testimony reflecting a misunderstanding of fundamental reservoir modeling processes, and reservoir pressures. (*See* Appendix 19 at pp. 12-14, 20-21, Response to Questions 64-65, 89, and 91.) **D2-81**
- Grossly misstating the amount of natural gas reported by DOGGR as having been produced from the Florin Gas Field. (*See* Appendix 21 at p. 4, Response To Question 17; Appendix 19 at pp. 13-14, Response To Question 65.) **D2-82**
- Grossly misstating the amount of water reported by DOGGR as having been produced from the Florin Gas Field. (*See* Appendix 21 at pp. 4-5, Response to Question 19; Appendix 19 at pp. 14-15, Response to Question 66.) **D2-83**
- Erroneously asserting that Ryder Scott's analysis utilized data from only one well, when in fact Ryder Scott's model achieved a good history match using production data from all five (5) wells that produced gas from the Florin Gas Field. (*See* Appendix 19 at p. 15, Response to Questions 68-69.) **D2-84**
- Erroneously asserting that Ryder Scott's analysis was based upon a depleted reservoir, rather than a water drive reservoir. (*See* Appendix 19 at p. 17, Response to Question 73.) **D2-85**
- Misinterpreting information included in the Florin Gas Field's well logs. (*See id* at p. 20, Response to Question 90.) **D2-86**

As summarized by Mr. Dames, Dr. Robertson's opinions regarding the size of the Florin Field are "based on a faulty understanding" of the Florin Field, ignore "clear evidence of good communication within the reservoir", and are contrary to data provided in the well logs, as well as other production records. (Appendix 20 at p. 6, Response to Question 25.) Mr. Palmer concurred, testifying that the "nature, number, and importance of Dr. Robertson's calculation and conceptual errors strongly suggest that he is unqualified to render the opinions he offers." (Appendix 19 at p. 21, Response to Question 92.) Mr. Mannon also explained that a graduate of **D2-87** **D2-88**

an accredited petroleum engineering program would not have made fundamental errors Dr. Robertson committed, such as relying on a book Mr. Mannon authored that was clearly inapplicable to the Florin Gas Field. (Appendix 22 at pp. 3-4, Response to Questions 3-16.)

Because Dr. Robertson's testimony is so rife with fundamental errors, the Commission need only acknowledge his points, and then detail the reasons why it has chosen to adopt the field boundaries delineated by Ryder Scott. *See* CEQA Guidelines § 15151 The Final EIR should thus state that the best available information provides substantial evidence for the conclusion that the surface area overlying the portion of the Florin Gas Field that SNGS will utilize for storage totals 287 acres.

B. Operational Field Pressures

The pressure numbers listed at page B-2 of the DEIR are confusing and should be clarified. The Florin Gas Field's initial field pressure was 1,668 psia (pounds per square inch absolute) at a measured depth in the borehole of 3,895 feet, which corresponds to a true vertical depth of 3,493 measured from sea level. (Appendix 19 at p. 7, Response to Question 28.) The bottom hole field pressure (3,895 ft MD, 3,493 ft ss) declined from 1,668 psia on 11/30/80 to 1,115 on 11/19/86. (*Id.* Response to Questions 30-31, and Exhibit B attached thereto.) Ryder Scott estimated that the initial field pressure at the cap rock was 1,677 psia, a figure it obtained by adjusting the initial measured pressure of 1,668 psia, for depth. (*Id.*, at p. 19, Response to Question 84).

The DEIR is also misleading at page B-2 where it states that the Proposed Project will operate at 1,804 psia. In fact, Mr. Palmer explained in his sworn testimony that "the maximum pressure the reservoir will exert on the cap rock will never exceed approximately 1,805 psia,

D2-88 (Cont.)

D2-89

D2-90

D2-91

D2-92

which is approximately 7.6 percent above the pressure at the same location in the model before any production took place." (Appendix 19 at p. 19, Response to Questions 84.) Those pressures were modeled at only three relatively small locations in the model layer at the cap rock. (*See id.* at p. 19, Response to Question 83, Exhibit F attached thereto at Figure 3 and Table 1.) In addition, the attachments to Ryder Scott's June 30 letter show a *range* in pressures that occur over several injection cycles. (*Id.* at Figures 4-6, and Table 2.) Accordingly, the DEIR should be corrected to state that the SNGS Project will operate at a range of pressures, and that it will exceed the reservoir's original pressure at some locations at the cap rock interface by no more than 8 percent, and will do so for only brief periods of time.

D2-92 (Cont.)

C. Length of Pipeline Segment 1

The DEIR states at page B-19 that Pipeline Segment 1, which would run between the compressor station and the wellhead is approximately 1.5 miles long. In fact, Pipeline Segment 1 will be 7342.2 feet long, which is 1.39 miles. The Final DEIR should be corrected to provide accurate values for this Pipeline Segment 1. Furthermore, the Final DEIR should recognize that SNGS plans to install a valve to further divide Segment 1 into two segments; the first segment from the wellhead site along Power Inn Road will be approximately 1,900 feet in length; the second segment to the compressor station will be approximately 5,700 feet in length.

D2-93

D2-94

D. Applicant Proposed Measures

Table B-5 of the DEIR omits several important applicant proposed measures. The Final EIR should be corrected to include those measures as follows. APM No. 4 on page B-31 should be revised to state that all project equipment and structures will meet a Class IV Seismic standard; i.e., a 0.4 g ground acceleration, instead of the 0.3g standard mandated for the site.

D2-95

(*See* Weatherwax (as referenced in the DEIR) 2008 at p.2.) This revision is important, because a Class IV standard increases by thousands of years the expected time of an earthquake event capable of posing any threat to project systems. (*Id.*) D2-95

APM No. 10 should be revised to include SNGS' proposal to conduct X-ray verification of 100% of all pipeline welds. (Weatherwax 2008 at p.2.) APM No. 10 should also be revised to include SNGS' proposal to include the above-mentioned valve between the wellhead and the compressor station, at approximately where the pipeline turns east from Power Inn Road, to reduce the potential mass flow of gas as a result of a pipeline failure along Pipeline Segment 1. (*See id.* at pp. 2, 8.) In addition, APM No. 10 should recognize the SNGS commitment to install pipeline and well shutoff valves with closure time capability of not more than 30 seconds. Finally, SNGS APM No. 10 should recognize that the compressor equipment will be designed and operated to limit the maximum injection pressure at the wellhead to1650 psi. D2-96

E. Florin Field Gas Volumes

Page B-2 of the DEIR includes inaccurate figures for the amount of natural gas produced from the Florin Field, and the amount of gas left in place after production ceased in 1987. Specifically, the DEIR states that 8.2 bcf was produced from the Field and that 5 bcf of gas was left in place. These figures do not comport with the best information currently available to SNGS. During the CPCN portion of this proceeding, SNGS submitted testimony of Bruce Palmer, the Ryder Scott reservoir engineer who developed a detailed model of the Florin Field using the Field's production records. Mr. Palmer testified that approximately 8.28 bcf was produced from the Field, and that 5.6 bcf of gas was left in place. (*See* Appendix 19 at p. 6, Response to Questions 22-25.) The Final DEIR should include these updated figures. D2-97

IV. ALTERNATIVES

The Snodgrass Slough Gas Field, the Thornton Gas Field and the Freeport Gas Field are identified in the DEIR as potential alternatives to the Florin Gas Field for development as a gas storage project serving the Sacramento area and particularly SMUD. The DEIR acknowledges that the screening analysis resulting in the identification of these alternatives did not take into account the economic feasibility of these alternatives. (DEIR, p. C-6.)

SNGS has evaluated the economic feasibility of the three identified alternatives utilizing the same unit cost assumptions as are being utilized in planning the SNGS Project, with appropriate adjustments to reflect their respective individual characteristics. The SNGS economic feasibility analysis is set forth in Appendix 23 to this letter. As that analysis shows, none of the alternative gas fields identified in the DEIR would achieve positive cash flows in operation – which means that none could attract equity or debt financing. D2-98

On the basis of the economic analysis set forth in Appendix 23, SNGS submits that none of the identified alternative gas fields is a "feasible alternative" as defined in the CEQA Guidelines to mean "capable of being accomplished in a successful manner within a reasonable period to time, taking into account **economic,** environmental, legal, social, and technological factors." (14 CCR § 15364; emphasis added.). D2-99

Finally, in light of the demonstration by SNGS in these comments that the Proposed Project will not result in any unmitigated significant impacts, none of the identified alternatives is environmentally superior to the proposed Project. D2-100

V. ISSUES TO BE RESOLVED

The DEIR identifies three issues to be resolved. SNGS address those issues in turn, below.

D2-101

A. Which Alternative Should Be Adopted?

SNGS supports the Commission's approval of the SNGS Project as proposed.

B. Which Mitigation Measures Should Be Adopted?

SNGS agrees that all mitigation measures described in the DEIR with respect to the Proposed Project, as well as the additional measures proposed by SNGS in this comment letter, should be adopted by the Commission.

D2-102

C. What Level Of Approvals Would Be Needed For The Use Of Depot Park For The Proposed Project?

In addition to the permit requirements identified for the SNGS Project in Table A-1 of the DEIR, the City of Sacramento, acting in its proprietary capacity as the owner and Depot Park, has retained discretionary approval authority over the proposed uses of Depot Park lands for the compressor station and pipeline rights of way. Specifically, the City's Army Depot Lease Agreement with Packard Bell Electronics, Inc., which was assigned to U.S. National Leasing, Inc. on March 10, 2000, requires the City's prior approval for the sublease by U.S. National Leasing, Inc. to SNGS authorizing those proposed uses of the Depot Park lands. SNGS anticipates that the Sacramento City Council will act on this matter at the same time it considers a proposed franchise agreement with SNGS and the proposed storage rights lease with SNGS.

D2-103

VI. MISCELLANEOUS CORRECTIONS

Executive Summary

Page ES-23 – Change "SNGS" to "SMUD" at the end of the first line of text.

D2-104

Section D – Environmental Analysis

Pages D.2-19 to D.2-21, Table D.2-7 – The commitment by SNGS to pay a premium rate to SMUD to ensure that 50% of the SNGS Project electrical load is generated from renewable resources should be recognized as an Applicant Proposed Measure. D2-105

Page D.2-28, Table D.2-11 – The entry for SO_x for the Proposed Project should be changed from "0.10" to "0.00" in accordance with the data presented in Appendix A. D2-106

Pages D.11.1 and D.11-2, Table D.11-1 – Sacramento Municipal Utility District should be added as an electricity provider in both the City of Sacramento and in the County of Sacramento. D2-107

Page D.13-3 – The size specified for Danny Nunn Park should be change to "approximately 16" acres in the second-to-last line of text, for consistency with the description in the first full paragraph on page D.8-17 and with the information (16.13 acres) provided by the Sacramento Department of Parks and Recreation at: D2-108

http://www.cityofsacramento.org/parksandrecreation/parks/sites/nunn_photo.htm).

Section F – Other CEQA Considerations

Page F-8 – The reference to "Table D.2-13" in the seventh line of text should be changed to "Table D.2-11" (which lists criteria pollutant emission estimates). D2-109

VII. CONCLUSION

SNGS requests that the DEIR be corrected and supplemented in accordance with the foregoing comments, and that the Commission's final Environmental Impact Report for the SNGS Project reflect the substantial evidence demonstrating that the Proposed Project will not result in any significant impacts – including potential impacts to public safety, ground water quality and noise levels. D2-110

Thank you for your consideration of these comments. If you have any questions or concerns, we would be happy to meet with you at your convenience.

Sincerely,

SACRAMENTO NATURAL GAS STORAGE, LLC

Jim Fossum
Chairman

Donald B. Russell
President

Appendices:

1. Weatherwax Memorandum, June 19, 2009
2. John Cornwell (Quest) Letter, June 17, 2009
3. Golder Associates Letter, June 10, 2009
4. Ryder Scott Letter re Stratigraphy, June 8, 2009
5. Ryder Scott Letter re Monitoring, June 8, 2009
6. ETIC Engineer, Inc. Letter, June 17, 2009
7. G.V. Chilingar – B. Endres Article *"Environmental hazards posed by the Los Angeles Basin urban oilfields: an historical perspective of lessons learned."*
8. D. J. Evans, *An Appraisal of Underground Gas Storage Technologies and Incidents, for the Development of Risk Assessment Methodology* (HSE Research Report RR605 – 2008)
9. Petroleum Engineers Paper 92647, "Urban Operations: Drilling and Completing a Gas Well on a Downtown University Campus", as presented at the SPE/IADC Drilling Conference held in Amsterdam, The Netherlands, 23-25 February 2005
10. Barnett Shale Compressor Station, Summary Acoustical Report, March 28, 2008
11. Noise Level Measures Sound Fighter Barrier Wall BAE Systems, Inc., April 7, 2009
12. Jim Fossum Direct Testimony (SNGS 8)
13. Don Russell Direct Testimony (SNGS 11)
14. Arthur Gimmy Direct Testimony (SNGS 16)
15. James Robert Fountain, Jr., Ph.D. Direct Testimony (SNGS 1)
16. Shawna Ackerman Direct Testimony (SNGS 13)
17. Letter to Commissioner Simon from James Shetler (SMUD), February 25, 2008 (SNGS 10)

D2-111

18. Barry Brunelle Direct Testimony (SNGS 5)
19. Bruce Palmer Reply Testimony (SNGS 27)
20. George Dames Reply Testimony (SNGS 20)
21. Eric Hadsell Reply Testimony (SNGS 23)
22. Robert Mannon Reply Testimony (SNGS 21)
23. Economic Feasibility Analysis



D2-111 (Cont.)

APPENDICES

APPENDIX 1

SERA
Sierra Energy and Risk Assessment, Inc.

MEMORANDUM

To: Jim Fossum
President
Sacramento Natural Gas Storage, LLC

From: Robert K. Weatherwax

Digitally signed by Robert K. Weatherwax
DN: cn=Robert K Weatherwax, o=Sierra Energy and Risk Assessment Inc., ou=President, email=rweatherwax@calweb.com, c=US
Date: 2009.06.19 16:24:15 -07'00'

Date: June 19, 2009

Subject: Review of *System Safety and Risk of Upset* by EDM Services Inc. dated September 2008.[1]

PURPOSE AND SCOPE

This memorandum examines the characterization of the Sacramento Natural Gas Storage ("SNGS") Project by EDM Services Inc. ("EDM") and how EDM quantified the risk associated with the SNGS Project as so characterized. This analysis is limited to the portion of the EDM analysis associated with their Individual Risk (IR) assessment for the project, on the basis of which the Draft EIR concludes that there are "Significant and Unavoidable Residual Impacts" with respect to the wellhead site and the pipeline.

Our analysis involves a careful review and evaluation of the EDM assessment from a risk methodology perspective as applied to the SNGS Project. In areas where we determine there to be either an inconsistency between the Project characterization evaluated by EDM and the Project as actually proposed by SNGS, or between the intended assessment as described in the draft EIR and what EDM actually assessed, we undertook a reevaluation to correct identified shortcomings in the EDM assessment. Due to the extensive nature of the issues, we were compelled to perform a complete reevaluation of the IR assessment. Included in this re-assessment was clarification as to what the IR standard really is and the unavoidable necessity to re-simulate many accident scenarios and characterizations and to re-quantify the casualty impacts of many of the hypothetical releases. As in the Risk Assessment supplement to the Proponent's Environmental Assessment ("PEA"), we were assisted in this work by Quest Consultants Inc., the vendor of the CANARY model used by EDM in the course of its subject risk assessment. Quest's role was to review the CANARY runs performed by EDM, identify issues and errors and redo potential releases selected by SERA staff.

D2-112

The re-calculated IR level is 9.03×10^{-7} (i.e., 0.903 in 1 million) – which meets the IR standard (as characterized by EDM) of an annual probability of injury or fatality of less than 1 in 1 million. As is explained in the following analysis, however, we believe that this re-calculated IR level remains

D2-113

[1] Dudek, Draft Environmental Impact Report (EIR) for CPCN Application No. A.07-04-013 dated April 2009, Appendix B.

unrealistically high. Furthermore, as discussed in the final section of this memorandum, the adjustments made to correct IR over-estimations by EDM carry over into the re-quantification of societal risk, which is very closely related to IR. Thus, the societal risk (which EDM concluded to be insignificant) is also further reduced below the already-insignificant levels computed by EDM.

D2-113 (Cont.)

BACKGROUND

EDM considered two probability risk standards in its evaluation of the SNGS project. One was a societal risk standard that endeavored to forecast the risk to society in general due to the presence of the project. EDM calculated that the SNGS Project easily falls within the permissible range for the societal risk, being always at least about a factor of ten lower than required depending upon the magnitude of the postulated accident.

D2-114

The second standard employed by EDM was an individual risk standard most commonly applied to California school safety evaluations to represent the likelihood of fatality of a hypothetical individual anywhere in the vicinity of a proposed facility (the Individual Fatality Risk ("IR") Criterion). The single value utilized in the assessment is a one in one million (1:1,000,000) probability of fatality per year, a value that matches the California Department of Education standard.[2] The results of the EDM quantitative risk assessment of the SNGS Project conclude that the project has an estimated individual risk of 6.9×10^{-6} (i.e., 6.9 in 1 million) per year or nearly seven times higher than the standard to which it is being compared. This result if accurate leads to the need to find that the risk from the project is a significant impact that must be mitigated and may require a finding of "Overriding Considerations" by the California Public Utilities Commission in order for the SNGS Project to receive a CPCN and be allowed to go forward. We take exception to the IR estimation methodology employed by EDM in general and assert that it does not conform to the approach mandated by the California Schools to determine nearby pipeline risk. We find that the assessment is also deficient in not actually conforming to the project as defined by SNGS including its general design and its normal modes of operation and in not taking into account special safety design and operational features included to enhance overall project safety. In this critique we will concentrate on correcting the EDM assessment mischaracterizations of the project and re-quantifying EDM's estimates to conform to the actual project as defined in the PEA as amended. In the process of this reassessment it was necessary to re-simulate various accidents to correct for release levels and durations of releases for various accident scenarios. In these cases the use of the CANARY model was employed under our direction by its vendor, Quest Consultants, Inc., to re-characterize these releases.[3]

D2-115

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[2] California Department of Education, *Guidance Protocol for School Site Pipeline Risk Analysis*, February 2007.

[3] CANARY Version 4.3 was used both in the EDM assessment and in this reassessment.

BRIEF DESCRIPTION OF KEY ERRORS IN THE EDM RISK ASSESSMENT

The key identified errors are separable into those associated with mischaracterizing the actual project in the modeling and assessment and errors in the modeling methods followed and applied. Key project mischaracterizations included:

- Continuing to count the estimated risk attributed to the SMUD to PG&E link even though the link was eliminated in the project modification submitted to the CPUC in September 2008 [4]; D2-116
- Treating the diameter of each wellhead as 20 inches instead of 7 inches thereby very much overstating the possible gas flow rate and resulting accident severity from a well during an inadvertent release; D2-117
- Modeling the maximum line pressure in the compressor station to SMUD line as 1,000 PSI instead of 700 PSI – thereby substantially overstating the size of any inadvertent release from that pipeline segment; D2-118
- Modeling the maximum line pressure from the wellhead site to the compressor station as 1,950 PSI instead of 1,650 PSI – thereby substantially overstating the size of any inadvertent release from that pipeline segment; D2-119
- Ignoring the different operating modes of the project; instead, treating it like a standard pipeline flowing at maximum pressure at all times – thereby overstating the magnitudes and frequencies of possible inadvertent releases; D2-120
- Failing to take note of, and reflect in the assessment, the additional project safety provisions provided in the project design, including an additional sectionalization value in the line from the wellhead site to the compressor station that is designed to be strategically placed to further reduce the risk from the main pipeline to residential and commercial building occupants and traffic especially in the segment along Power Inn Road; D2-121
- Failing to take note of and reflect in the assessment, the specially upgraded control and augmented valve actuation system elements provided in the design that will detect and shutoff system operations within 30 seconds of detection of an inadvertent release – thereby reducing the magnitude of any such releases; and D2-122
- Underestimating the reduction in failure probability from combining deeper burial with thicker pipe walls and ignoring totally the further benefit of very deep burial of about 2,800 ft of pipeline from south of Elder Creek road all the way to beyond Morrison Creek thereby overstating the project risk. D2-123

In coordination with Quest staff the following key errors were discovered in the CANARY accident modeling for the EDM risk assessment.[5] D2-124

- The magnitudes of each and every postulated release associated with full pipeline ruptures

[4] SNGS Amendment to Application No. 07-04-013, filed September 12, 2008.

[5] See discussion of errors in a letter to SNGS from John B. Cornwell, Principal Engineer, Quest Consultants, Inc. ("the Quest Comment Letter").

were profoundly overstated by using the instantaneous release at one second after rupture to calculate the overall rate and total amount of gas release that would contribute to the simulated accidents thereby ignoring the suggested and much more reasonable default value supplied by the CANARY model. Release magnitudes were overstated by factors of from 5 to 10 or more depending upon the release.

D2-124 (Cont.)

- EDM treated prompt, non-fire-inducing ignitions following inadvertent releases as contained explosions instead of flash fires, even though the SNGS Project will be sited in an unobstructed area. CANARY permits the analyst to specify what level of assumed containment would be seen by the released gas when it does ignite during a release scenario featuring explosion of accumulating gases. EDM assumed in its risk assessment that there would be medium obstacle density at the project site that would tend to trap and constrain the escaping gas while, in fact, there is very low obstacle density. This mischaracterization of the SNGS Project setting is even more surprising because EDM modeled the pipe ruptures as always occurring at a 45 degree angle of release relative to the ground and the wellhead ruptures as always occurring at a 90 degree angle of release relative to the ground. At such angles of release the buoyant gas, flowing under very high pressure, would be thrust upwards from the ground and continue to rise above the few structures that are near the pipeline route. Thus, the escaping gas would not be confined or congested as it mixed with the atmosphere and instead would be rapidly diluted by air down to and below its upper flammability limit of 15 percent before any ignition. Much like throwing a match on a gasoline spill in an open field, were a gas release from the SNGS Project to ignite and very rapidly combust, it would cause a slight overpressure wave that would be felt nearby but would be of no consequence to unsheltered individuals. Severe harm could only occur to an individual exposed directly to the very high flame temperature for some duration of time such as would occur with prompt ignition from the torch fire release scenario. Thus, a flash fire – not an explosion – would occur in a non-fire release scenario featuring prompt ignition with substantially reduced potential danger.

D2-125

- CANARY produces thermal power flux isopleths for torch fire release scenarios. For its assessment of SNGS Project risk EDM chose to employ 8000 Btu/hr-ft^2 isopleths. These isopleths spread out from the flame and define, in the EDM 8000 Btu/hr-ft^2 case, the mortality zone for the various torch fire accidents.[6] The exposure for 50% mortality (*i.e.*, lethal dose (LD) 50) is 30-second exposure of an unprotected individual at 8,000 Btu/hr-ft^2.[7] The dimension of the isopleth is determined by the amount of combustible gas that is available to burn over a 30 second period. To determine the dimensions of this isopleth for its analysis, EDM used the instantaneous mass release rate found at the instant of one second

D2-126

[6] The implausibility of the EDM explosion scenarios is further addressed in Quest Comment Letter.

[7] *Op. sit.*, California Department of Education, p. 4-18, Figure 4-4.

after rupture; however, in reality, that mass release rate would decay rapidly with time.[8] EDM's procedure thus failed to match the impact modeled with the duration of the flame necessary to cause the impact. EDM's overstatement of the total possible gas release substantially enlarged the LD 50 zone and inaccurately attributed greater apparent risk to the SNGS Project. The level of risk overstatement is dependent upon the size and pressure of the pipeline and the throughput rate at the time of the accident.[9]

D2-126 (Cont.)

SUMMARY RESULTS OF RE-QUANTIFICATION

We undertook a step-by-step process to correct the most significant inaccuracies detected in the EDM assessment. The following table lists these steps in a sequential fashion.

ADJUSTMENT DESCRIPTION	ADJUSTMENT MAGNITUDE	RESULTING IR	REMARKS
EDM IR PREDICTION	0	6.86E-06	Starting Point
DROP SMUD PGE LINK & ASSOCIATED ACCIDENTS	-1.43E-07	6.71E-06	Both Commercial and Traffic
REQUANTIFY EXPLOSIONS WELLHEAD	-1.49E-06	5.23E-06	Comm, Resid & Power Inn Traffic
REQUANTIFY EXPLOSIONS PIPELINE	-3.53E-07	4.88E-06	Comm, Resids Traffic- 3 Roads
CHANGE WELL DIAMETERS TO 7" FROM 20" FOR TORCH FIRE	-2.48E-06	2.39E-06	Comm & Power Inn Traffic
REDUCE TORCH FIRE TRAFFIC RISK WITH LOW PRESSURE	-6.03E-08	2.33E-06	Part 1 Power Inn, Elder Ct. & Fruitridge Traffic
REDUCE TORCH FIRE TRAFFIC RISK FOR DEEP BURIAL AND REDUCED RATE	-1.77E-07	2.15E-06	Part 2 Power Inn, Elder Ct. & Fruitridge Traffic
FIX SMUD LINK TORCH FIRE RISK FOR OPERATING PRESSURE/RELEASE SIZE	-6.07E-07	1.54E-06	SMUD LINK Torch Fire 210 not 500 feet
REDUCE RES. TORCH FIRE RISK WITH CORRECTED PRESSURE/RELEASE SIZE	-2.70E-08	1.51E-06	Residential Exposure Adjustment
REDUCE COMM TORCH FIRE RISK WITH CORRECTED PRESSURE/RELEASE SIZE	-5.27E-07	9.85E-07	Commercial Exposure Adjustment
ADJUST FAILURE RATE FOR FULL IMPROVEMENTS IN RPNG DEPTH CLASS	-8.02E-08	9.03E-07	Failure rate applies to all pipeline risk

D2-127

As can be seen from the table we delineate ten step-by-step changes in the EDM estimates to make them progressively more consistent with the SNGS Project as proposed. We next describe how an d why, in each of our step-by-step corrections, we reduced the estimated risk employing EDM's methods as corrected as little as possible to give as full a utilization of EDM's intended risk assessment approach as we can discern it, limited only by the need to correct what we believe to be indisputably erroneous inputs and procedures. As is shown in the table above, the IR estimate stated in the EIR is 6.86×10^{-6} (i.e., 6.86 in 1 million) – which is about seven times higher than the California School Standard to which EDM compares its result. Following our adjustments to the EDM IR calculation, the IR declines to 9.03×10^{-7} (i.e., 0.903 in 1 million) – which is approximately 8 times lower and well within the bounds of the California standard invoked by EDM.

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[8] See Quest Comment Letter at p. 5, Figures 1.

[9] We acknowledge that EDM did correctly match flame duration with the defined impact level in its modeling of the 1" leak releases - where the 60-second average release rate was employed consistent with the CANARY default procedure.

D2-128

Elimination of the SMUD-PG&E Pipeline Link

The documentation of Appendix B of the EIR draft is not sufficiently detailed to know the set of inadvertent events quantified for the SMUD-PG&E Link. To better study and review the individual events, we requested and received the complete EDM spreadsheet that contains, *inter alia*, the individual IR events including those associated with the Link.[10] EDM had quantified one commercial sector incident and 3 separate traffic related incidents associated with the SMUD-PG&E link total event probability of 1.43×10^{-7} per year. Deleting those hypothetical accidents reduced the EDM computed IR to 6.71×10^{-7}.

D2-129

Re-quantification of Modeled Explosion Accidents from Wellhead

There were two major defects in the assessment of the explosion accidents attributable to the wellhead:

i) Modeling each well as 20 inches in diameter instead of 7 inches in diameter and assuming each well could release at a 2,700 lb/sec flow rate; and

D2-130

ii) Mischaracterizing a release from the wellhead as being capable of being sufficiently contained to be explosive.

D2-131

As shown in our risk assessment submitted as a supplement to the Applicant's PEA,[11] the maximum possible flow from an individual well is 60 mmcf/d (equivalent to about 22 lb/sec or about 1,000 times less than that presented in the EDM assessment). This would very much reduce the possible hazard, but even more important is the method of explosion modeling as compared to the risk criteria EDM chose to employ. EDM chose to employ a 1 psig overpressure as its risk criterion, because that could result in an overpressure "high enough to have a 1% probability of serious injury or fatality to occupants of reinforced concrete or reinforced masonry buildings due to flying glass and debris."[12]

D2-132

In its modeling EDM found that 1 psig overpressure would extend to a distance of 401 feet in a full rupture, and to a distance of 48 feet in a 1-inch leak from the wellhead plumbing – when they employed low reactivity gas and medium obstacle density in their CANARY modeling.[13] These lethality zones were applied to the commercial, residential and traffic on Power Inn Road to

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[10] Westerneyer, John, Email to Al Jahns dated April 22, Release Tables_05.xls.

[11] Weatherwax, Robert *et al, Probabilistic Risk Assessment Sacramento Natural Gas Storage Project*, SERA Document # 08-1124 dated July 8, 2008, page 30 Table III - 4.

[12] *Op sit*, Dudek, Appendix B, page B-29

[13] *Ibid*, Table 6.3-1.

estimate contribution to IR. As discussed *supra* and in the Quest evaluation, the correct modeling assumptions are medium reactivity gas (as is actually found in the PG&E pipeline and is expected to be found in the working gas in the Florin Field as a worst case) and low obstacle density. Applying these corrections results in a maximum possible overpressure wave of .38 psig -- resulting in no fatalities. The EDM computed explosion fatality risks from the Wellhead were $3.47x10^{-7}$, $1.49x10^{-7}$ and $9.90x10^{-7}$, respectively, for residential, commercial and Power Inn traffic. This total risk contribution of $1.49x10^{-6}$ is eliminated in the corrected modeling, leaving a residual IR risk of $5.23x10^{-6}$.

D2-132 (Cont.)

Re-quantification of Modeled Explosion Accidents from 16-Inch Pipelines

Similar to the EDM's wellhead release modeling just discussed, there were two major defects in the EDM assessment of the explosion accidents attributable to the 16-inch pipelines:

D2-133

i) Modeling the pipeline pressure at all times between the wellhead site and the compressor station as 1,965 psig – instead of a maximum pressure of 1,650 psig as specified in the PEA; and modeling the pipeline pressure at all times between the SMUD pipeline and the compressor station as 1,000 psig -- instead of a maximum pressure of 700 psig as specified in the PEA; and

ii) Mischaracterizing a release from these pipelines as being sufficiently confined to be explosive.

EDM considered lethality ranges of up to 203 feet for the higher pressure pipeline and up to 122 feet for the lower pressure pipeline. In reality, for the same reasons discussed relative to the EDM wellhead explosion scenario, lethality could not occur from such a vapor cloud explosion from the pipelines. EDM computed respective explosion risks from both pipeline segments (they were commingled in the EDM assessment) of $4.57x10^{-8}$, $1.57x10^{-8}$, $2.28x10^{-7}$, $5.35x10^{-8}$, and $9.47x10^{-9}$ for residential areas, commercial areas, traffic along Power Inn Road, traffic along Elder Creek Road, and traffic along Fruitridge Road. This total contribution of $3.53x10^{-7}$ is eliminated in the corrected modeling – leaving a residual IR risk of $4.88x10^{-6}$

D2-134

Re-quantification of Modeled Torch Fire Accidents from Well Releases

The fatal flaw in EDM's well modeling was the release rate assumed in a full rupture of a well. In that instance, the assumption that the well was 20 inches in diameter with a down-hole pressure of 1,965 psig resulted in a predicted release rate of approximately 2,700 lb/sec.[14] In contrast, as specified in the SNGS PEA, the maximum flow rate from an uncontrolled well at peak down-hole pressure is about 60 mmcf/d, equivalent to about 22.2 lb/sec. The EDM 1-inch leak case seemed to modeled correctly; in that case the EDM results show a release rate of about 22 lb/sec. By coincidence, and as just noted, that amount is just about exactly what the maximum rupture well casing release rate actually would be given a flow of 60 mmcf/d. Assuming long-term continuation of the leak – as EDM did in spite of the safety features

D2-135

[14] Equivalent to a release rate of about 7.3Bbcf/d; thus, emptying the entire depleted Florin reservoir via one well in one day.

D2-136

specified for the SNGS Project that include multiple redundant shutoff vales that act to shutdown the flow in a few seconds -- EDM projected 8,000 Btu/hr-ft^2 lethality distances of 266 feet for the full rupture and 28 feet in the case of the 1-inch leak. EDM discounted any casualties from the 1-inch leak due to the very small lethality zone. Since the correct release rate for the full case rupture is essentially identical to EDM's 1-inch lethality zone, we discounted the full rupture as a source of contribution to IR as well, just as we did in the PEA risk assessment.

EDM computed torch fire risks from the Wellhead of 1.07×10^{-6} and 1.42×10^{-6}, respectively, for the commercial sector and Power Inn Road traffic. This total contribution of 2.49×10^{-6} to EDM's calculated IR is eliminated in the corrected modeling – leaving a residual IR computed risk of 2.38×10^{-6}.

D2-135 (Cont.)

Reduced Torch Fire Traffic Risk from Reduced Pipeline Pressures

In this adjustment we address exclusively the mistakes associated with the overstatement of maximum operating pressures in the two segments of 16-inch pipeline present in the EDM risk assessment. We address later the mistake in the release rate used in the full rupture torch fire cases as it relates to EDM's calculation of risk to traffic.

As described above, EDM assumed that the 16-inch line from the wellhead site to the compressor station would see 1,965 psig pressure all of the time. The correct maximum pressure, which we estimate would only be seen about ten per cent of the time during SNGS Project operations, is 1,650 psig.[15] A similar, but even more egregious situation, is present in EDM's risk assessment of the pipeline segment from the compressor station to the SMUD pipeline. In that segment EDM assumed that pressure of a 1,000 psig would be present at all times. This, of course, is impossible. Were such a high pressure seen in that segment of the SNGS pipeline, which directly connects to the SMUD 700 pipeline, it would promptly rupture the SMUD 20-inch pipeline. The PEA risk assessment used a worst case peak pressure of 700 psig and assumed it would be present about 43% of the time. We directed Quest to rerun these cases exactly as EDM performed them, other than to correct for the operating pressures seen in the pipes prior to the releases.

D2-137

The resulting reductions in lethality distance from the earlier EDM results are 68 feet (755 from 823 feet) for the rupture of the wellhead to the compressor pipeline segment, 5 feet (65 from 70 feet) for a 1-inch leak release from the same line, and a 60 feet (359 from 419 feet) for a rupture of the pipeline segment between the SMUD pipeline and the SNGS compressor. Scaling these results for impact on the EDM IR assessment results in a reduction for Power Inn Road, Elder Creek Road and Fruitridge Road releases of 6.09×10^{-8} – leaving the net IR risk from the EDM assessment as 2.32×10^{-6}.

[15] *Op sit*, Weatherwax *et al*, page 10, Table II-1

Reduce Residual Torch Fire Traffic Risk for 30 Second Fatality Exposure and Burial

The torch fire traffic risk adjustment for overstated pipeline pressure is found *supra*. The following discussion addresses the final two key mistakes found in the EDM traffic risk assessment.

i) As noted in the summary comments section of this memo, the LD 50 dose is 30 seconds exposure of an unprotected individual at 8,000 Btu/hr-ft^2. The dimension of the isopleth is determined by the amount of combustible gas that is available to burn over a 30-second period. To determine the dimensions of this isopleth for its analysis, EDM chose to use the instantaneous mass release rate found at the instant of 1 second after rupture. In reality, the maximum sized isopleth that can be defined is one employing all the gas released during the first 30 seconds – and conservatively assuming that the released gas burns at a constant rate over the 30-second period instead of at a rapidly declining rate down to the level consistent with the pipeline flow. In our re-calculation we corrected EDM's modeling error.

D2-138

ii) The EDM assessment took no account of the very deep burial that begins south of Elder Creek Road and extends all the way to beyond Morrison Creek. This burial will be deeper than 20 feet on average and is not believed to afford much if any possibility of risk to drivers along Elder Creek Road.

Both the 16-inch pipeline from the wellhead site and the 16-inch pipeline from the compressor station to the SMUD pipeline were remodeled at correct project maximum pressures to account for 30 seconds averaging of the release and the isopleths were then determined. These new modeling results were then overlaid on a map of the SNGS Project to determine new lethality zones along the pipeline per the EDM assessment. Further adjustments were made for the Elder Creek Road segment to account for the depth of burial of the pipeline.

D2-139

Along Power Inn Road the lineal extent of pipeline contributing to the LD 50 zone was recalculated to be 1,983 feet following a rupture (versus EDM's calculation of 2,320 feet), and to be 888 feet following a 1 inch leak (versus EDM's calculation of 1,405 feet). The re-estimated total risk along Power Inn declines from 2.99×10^{-7} to 2.16×10^{-7} for a reduction of 8.24×10^{-8} (including the reduction attributable to the corrected pressure level).

D2-140

Crossing Elder Creek Road the lineal extent of pipeline contributing to the LD 50 zone (ignoring mitigation from deep burial) was recalculated to be 740 feet following a full rupture and 146 feet following a 1-inch leak. The deep burial zone encompasses 577 feet of the line in the full rupture scenario and all 146 feet from the 1-inch leak scenario. We assumed that the burial would reduce the likelihood of lethality by a factor of ten. To ease computations in a revised EDM spreadsheet, we reduced the length of pipeline by 90 per cent where buried. Thus, the lineal extend of pipeline contributing to the LD 50 zone was recalculated to be 221 feet following a full rupture (versus EDM's calculation of 1,070 feet), and 15 feet following a 1 inch leak (versus with EDM's calculation of 190 feet). The re-estimated total risk across Elder Creek Road

D2-141

declines from $1.59x10^{-7}$ to $2.71x10^{-8}$ for a reduction of $1.32x10^{-7}$ (including the reduction attributable to the corrected pressure level). D2-141 (Cont.)

Approaching Fruitridge Road, the lineal extent of pipeline contributing to the LD 50 zone was recalculated to be 190 feet following a full rupture (versus EDM's calculation of 520 feet), and 10 feet following a 1-inch leak (versus EDM's calculation of 45 feet). The re-estimated total risk approaching Fruitridge Road declines from $0.352x10^{-7}$ to $0.114x10^{-7}$ for a reduction of $2.38x10^{-8}$ (including the reduction attributable to the corrected pressure level). D2-142

The total reduction from this element of the recalculation becomes the sum of the savings identified for each of the three roads minus the improvement already claimed from the pressure reduction in the pipelines: $0.82x10^{-7} + 1.32x10^{-7} + 0.24x10^{-7} - 0.61x10^{-7} = 1.77x10^{-7}$. D2-143

Correct SMUD Link Torch Fire Risk for Operating Pressure/Release Rate

EDM had two separate torch fire release accidents contributing to project IR for the pipeline connecting the SNGS compressor station with the SMUD pipeline: full rupture and one inch leakage. We re-quantified these torch fire releases taking into account the following three errors in the EDM modeling: D2-144

i) Modeling the pipeline pressure at all times between the compressor station and SMUD pipeline as 1,000 psig instead of a maximum pressure of 700 psig as specified in the PEA;

ii) Employing in the full pipe rupture scenario the instantaneous release rate at 1 second following the rupture for the entire accident release period, instead of averaging the release rate over at least the first 30 seconds following the release; and D2-145

iii) Averaging the commercial sector impacts for the higher pressure pipeline with similar impacts for this lower pressure line for commercial sector risk – resulting in more difficulty in re-quantifying IR for each pipeline. D2-146

Since these adjustments change the torch fire lethality zone, we chose to estimate from the appropriate SNGS Project maps the number of lineal feet of pipeline that should be used in the re-quantification of the torch fire risk.

We began by disaggregating the EDM-estimated contributions to commercial sector risk from each pipeline. This task was simplified because EDM estimated no discernable commercial sector risk associated with a 1-inch leak from either pipeline, and considered only the full rupture torch fire releases. In total, EDM estimated commercial IR risk of $1.65x10^{-6}$. This is about 25% of the total calculated IR and significantly larger than any other quantified contributor to IR. We chose to disaggregate this risk into that attributable to each pipeline by assuming that the 10,315 lineal feet of pipeline that EDM identified as contributing on both sides of the pipeline to commercial risk was composed of the entire 4,224 feet of the pipeline segment between the SMUD line and the SNGS compressor station, and 6,091 feet of the entire 7,600 feet-long D2-147

pipeline from the compressor station to wellhead site.[16] Based upon this disaggregation, the risk for the SMUD connection segment is 6.76×10^{-7} and the higher pressure pipeline risk was the remainder or 9.75×10^{-7}. In truth, it doesn't make much difference how we chose to disaggregate this release because all risk in both pipelines is accounted for in the course of our re-estimation and compared with IR for both pipelines as estimated by EDM. We note, however, that it was quite inappropriate as a matter of modeling protocol for EDM to lump together isopleths from a 700 psig maximum pressure pipeline with those of a 1,695 psig maximum pressure pipeline.

The CANARY result for our modeling of an 8,000 Btu/hr-ft^2 isopleth is 210 feet (versus the 700 feet resulting from the EDM modeling). This reduced isopleth distance leads to estimation of 480 feet of commercial property to the east and 381 feet to the west, for a total on both sides of 430 feet (as is the convention used in the EDM modeling). We estimate a total IR risk of 6.89×10^{-8} as contrasted with the EDM estimate of 6.76×10^{-7} as derived above. This results in a reduction in IR of 6.07×10^{-7}.

D2-147 (Cont.)

Reduce Residential Torch Fire Risk with Corrected Pressure/Release Rate

EDM had two separate torch fire release accidents contributing to residential IR for the pipeline segment connecting the compressor station with the wellhead site: full rupture and 1-inch leakage. We re-quantified these torch fire releases taking account of the following two errors in the EDM modeling relevant to the residential sector for the higher pressure pipeline.

i) Modeling the pipeline pressure between the compressor station and wellhead site as 1,965 psig at all times, instead of a maximum pressure of 1,650 psig as specified in the PEA; and

ii) Employing in the full pipe rupture scenario the instantaneous release rate at 1 second following rupture for the entire accident release period, instead averaging the release rate over at least the first 30 seconds following the release.

D2-148

Since these adjustments change the torch fire lethality zone we chose to estimate from the appropriate SNGS Project maps the number of lineal feet of pipeline that should be used in the re-quantification of the torch fire risk for residential sector on the west side of Power Inn Road. As in the other, non-traffic-related torch fire cases, the 1-inch leakage was dismissed as unimportant for risk.

D2-149

The CANARY results for our redo for an 8,000 Btu/hr-ft^2 isopleth for the 1,695 psig pipeline is 357 feet (versus the 700 feet employed in the EDM modeling). This reduced isopleth distance leads to a estimation of 1,983 feet residential property exposure to the west (versus the EDM estimate of 2,320 feet). We estimate a total IR level of 1.59×10^{-7}as contrasted with an EDM estimate of 1.86×10^{-7}. This results in a reduction in IR of 2.70×10^{-8}

D2-150

[16] *Op sit*, Dudek page Appendix B-42.

Reduce Commercial Torch Fire Risk with Fixed Pressure/release Rate/extended Burial.

EDM had two separate torch fire release accidents contributing to commercial IR for the commercial development along the pipeline connecting the compressor station with the wellhead site: full rupture and 1-inch leakage. We re-quantified these torch fire releases taking account of the following four errors in the EDM modeling relevant to the commercial sector for the higher pressure pipeline:

i) Modeling the pipeline pressure at all times between the compressor station and wellhead site as 1,965 psig instead of a maximum pressure of 1,650 psig as specified in the PEA;

ii) Employing in the full pipe rupture scenario the instantaneous release rate at 1 second following rupture for the entire accident release period, instead averaging the release rate over at least the first 30 seconds following the release;

iii) Averaging the commercial sector impacts for the higher pressure pipeline with similar impacts for the lower pressure line, resulting in more difficulty in re-quantifying IR for each pipeline; and

iv) Taking no account of the very deep burial that begins well south of Elder Creek Road and extends all the way to beyond Morrison Creek, which will be deeper than 20 feet on average and is not believed to afford much if any possibility of risk in relation to the commercial activities paralleling the pipeline – especially due to the 200+ feet between the pipeline and most of the commercial property.

D2-151

Since the first two adjustments change the torch fire lethality zone, we chose to estimate from the appropriate SNGS Project maps the number of lineal feet of pipeline that should be used in the re-quantification of the torch fire risk for the entire. As in the other, non-traffic-related torch fire cases, the 1-inch leakage case was dismissed as unimportant for risk. Per the discussion above in the instance of the SMUD link pipeline, we "assigned" the commercial sector higher pressure pipeline risk the value of 9.75×10^{-7}.

D2-152

The CANARY results for our modeling for an 8,000 Btu/hr-ft^2 isopleth for the 1,695 psig pipeline is 357 feet (versus the 700 feet employed in the EDM modeling). This reduced isopleth distance leads to a estimation of 3,590 feet of commercial property exposure to the east and south, and 4,160 feet to the west and north, for a total on both sides of 3,880 feet (as is the convention used in the EDM modeling) excluding consideration of the very deep burial segment. The deep-buried pipeline segment faces 440 feet of exposed commercial property to the east and 1,720 feet to the west, resulting in a two-sided deep burial for 1,080 feet. Eliminating that length of pipeline , due to the extended distance from any structures within the isopleth, we calculate a total of 2,800 feet of two-sided lineal pipeline capable of contributing to a lethality zone (versus the 6,090 feet computed by EDM). We estimate a total IR level of 1.59×10^{-7}as contrasted with an EDM estimate of 1.86×10^{-7}. This results in a reduction in IR of 2.70×10^{-8}.

D2-153

Adjust Failure Rate for Full Improvements in Piping Depth/Class

EDM has a writeup delineating ten "*Applicant proposed mitigation measures.*"[17] Eight of the mitigation measures, including the very important sectionalizing valve on the high pressure pipeline that runs along Power Inn Road, are completely ignored in the modeling. The remaining two are partially included in the EDM Risk Assessment. The two considered partially in the assessment are deeper burial to at least 6 feet, where 3 feet would satisfy safety criteria, and using Class 4 pipe thicknesses in what is universally understood to be a Class 3 pipeline route. Deeper burial is intended to reduce the likelihood of trenching or other "outside forces" causing failure of the piping. This failure mode is found in most failure data bases to be the single most likely mode of pipeline failure. The second most likely failure cause is the combination of external and internal corrosion. Increasing the thickness of the piping from Class 3 to Class 4 means reducing the safety factor from 0.5 to 0.4, thereby substantially increasing the thickness of the piping needed to serve a given maximum pressure.[18] Increased pipe wall thickness helps both by warding off corrosion and by reducing the susceptibility of the pipelines to "outside forces."

D2-154

EDM seems to accept that these safety mitigation measures will help improve safety and reduce risk; however, we believe that they do not fully credit these measures for their potential to reduce the frequency of failures in the pipelines. EDM is to be commended for finding citations that attempt to quantify the beneficial impact of these actions. They cite European studies that find that 6 foot burial reduces failure from third party damage by about 30%, and that increased thickness of piping reduces failures initiated by "Outside Forces" by about 25%.[19] Applying these data, they reduce the 30% of the overall piping failure rate attributable to Outside Forces by 33%. This reduction is labeled an assumption and they did not attempt to apply these Applicant planned safety mitigation measures to any other failure mode(s), so their overall failure rate declines from 0.216 failures per 1,000 miles per year to 0.194 for a reduction of 10%. We find this result deficient in two ways:

D2-155

i) the overlapping credit given to the two safety measure is underestimated; and

ii) credit against corrosion failure should be estimated for the increase in the thickness of the piping.

D2-156

We think a more appropriate way to compute the credit to reduction in Outside Forces failures is to use a logic tree approach as follows: let f_0 be the original Outside forces failure rate and r_1 and r_2 be the failure rate improvements seen as a result of the two safety mitigation initiatives; *viz*, deeper burial and thicker piping. Compute the resulting failure rate as

D2-157

[17] *Op sit*, Dudek Page Appendix B-51.

[18] *Op Sit*, Weatherwax *et al*, Page 15.

[19] *Op sit*, Dudek P. Appendix B-18 & B-21.

$f_r = f_0*(1- r_1)*(1 - r_2)$. Using values of .065 for f_0, .30 for r_1 (thicker piping) and .25 for r_2 (deeper cover), we compute a final failure rate of 0.034 failures per 1,000 miles per year due to Outside Forces as compared to a value of 0.043 failures per 1,000 miles per year due to Outside Forces employed by EDM.

D2-157 (Cont.)

Per EDM, the failure rate from corrosion is estimated to be 0.027 failures per 1,000 miles per year.[20] Increasing the thickness of the piping by more than 25 per cent as proposed by SNGS should decrease corrosion by a substantial amount and that is in the absence of consideration of the new standards for High Consequences Areas ("HCA") where frequent internal and external inspection will be required to reduce corrosion induced failures from the level currently being observed in the installed pipeline population. Consequently, reducing the corrosion frequency by 25 % from 0.027 to .020 failures per 1,000 miles per year is an extremely modest and conservative credit to claim in our professional judgment. In total we believe that a reduction in the overall piping failure rate from 0.194 to 0.178 per 1,000 miles per year, equivalent to a further 8.25 percent reduction in failure rate from that used by EDM, is appropriate. Referring back to the table on page 5 of this memo, it can be seen that we have multiplied the resulting 91.75 percent failure rate fraction to the 9.85×10^{-7} residual probability of failure since each and every contributing failure is multiplied by the overall pipeline failure rate. This results in a diminishment of IR by 8.12×10^{-8}.

D2-158

FINAL COMMENTS AND STATUS OF ANALYSIS

The IR level derived in this paper of 9.03×10^{-7} per year (i.e., 0.903 in 1 million) – an 87 percent reduction from the EDM estimate – now conforms to the IR standard as construed by the CPUC consultant. All of the adjustments made in the RI calculation also apply to the societal risk assessment so it should be reduced by a comparable amount though we did not perform that calculation for this report.

D2-159

We believe that the residual Individual Risk estimate, even with the corrections we have documented, remains unrealistically high due to the following considerations:

- The benefits of key safety devices designed into the SNGS Project, including the sectionalizing value placed in the higher pressure pipeline in order to reduce civilian risk, were ignored.

D2-160

- The SNGS Project was not modeled as a cycling project, but rather as a continuous-flowing pipeline, so that no consideration was given to the fact that during the vast majority of time the project will be operating at less than full output and maximum operating pressures – thus reducing risk still further.

D2-161

- We believe there to be significant modeling and quantification issues regarding the flash fire accidents and interior explosions quantified in the EDM report, but we did not adjust

D2-162

[20] *Ibid*, Page Appendix B-21.

those in our analysis due to the relatively small magnitude of their projected risk contributions.

- The method employed by EDM to attempt to estimate the risk from a given failure along a given pipeline segment is excessively crude and overstates risk. An areal calculation should be used to incorporate consider of the direction of release and potential isopleth area of the release in order to distinguish high pressure but low release rate events from more severe releases that feature both high pressure and high release rate. The PEA Risk Assessment provides one method of doing such an adjustment.[21]

The quantitative risk assessment that we performed during the design stage of the SNGS Project served effectively to guide safety optimization in the SNGS Project design. It seems highly credible to us that, built to the resulting design, the SNGS Project will indeed satisfy SNGS Management's voiced aspirations and explicit instructions to all involved contractors and consultants to produce the safest gas storage project in the world.

D2-162 (Cont.)

D2-163

D2-164

[21] *Op Sit*, Weatherwax *et al*, p.25

STAFF RESUME

ROBERT K. WEATHERWAX

EMPLOYMENT EXPERIENCE:

1981 - Present	President, Sierra Energy & Risk Assessment, Inc., Roseville, CA
1980 - 1981	Visiting Scientist, Energy and Resources Group, University of California, Berkeley, CA
1977 - 1980	Chief Energy Forecaster, California Energy Commission, Sacramento, CA
1977	Staff Scientist, Science Applications, Inc., Palo Alto, CA
1974 - 1977	Staff Scientist, School of Engineering, Princeton University, Princeton, NJ
1969 - 1974	System Safety Supervisor, McDonnell Douglas Astronautics Company, Huntington Beach, CA
1967 - 1969	Safety and Reliability Engineer, Boeing Space Center, Kent, WA

As the founder and President of Sierra Energy & Risk Assessment, Inc. (SERA), Mr. Weatherwax is presently involved in the twin topics of (1) risk assessment and comparison, and associated cost benefit analysis; and (2) energy demand and supply assessment, and policy evaluation.

He has had over twenty years of experience in safety analysis of commercial power generation and isotope power systems for space application. He has worked broadly in the area of nuclear fuel cycle risk assessment, and in reliability and failure mode assessment of complex systems. He has contributed to the original development of elements of fault tree, sequence tree (a.k.a., FAST), and event tree analyses, and has applied these methods in analysis of light water nuclear power plants, nuclear fuel cycles, nuclear waste handling, transportation and disposal, radioisotope thermal generators, strategic weapons systems, and launch vehicles. He is an engineer by formal education with a minor in economics, and has applied these disciplines in numerous systems engineering and evaluation efforts, particularly related to energy demand forecasting and policy assessment.

Mr. Weatherwax is perhaps best known in the field of nuclear reliability and risk assessment for two things: (1) lead authorship of the Reliability Assessment of the Shuttle which accurately forecasted the Challenger failure mode and probability of catastrophic failure three years before it failed, and (2) 1976 debate before

the American Physical Society with Norman Rasmussen, Project Director, on the accuracy of the Reactor Safety Study (WASH-1400). (His position, described in greater detail in a September 1975 article in the Bulletin of the Atomic Scientists, was subsequently adopted by the Nuclear Regulatory Commission.) In the field of energy assessment, he is recognized as having developed the first series of methodologies to accurately project future California electricity and natural gas demand.

As a McDonnell Douglas Astronautics Company (MDAC) Engineering Supervisor, Mr. Weatherwax was a principal author of a preliminary safety analysis report for the NASA 50 kWe space station power system. He later was manager for the Environmental Impact and Risk Assessment on the MDAC team selected by the Air Force Weapons Laboratory (AFWL) to perform safety analyses of LES 8/9 and Viking missions. After leaving MDAC he continued as a consultant to MDAC, and subsequently became a consultant to Teledyne Energy Systems in their support of the AFWL's space nuclear safety responsibilities. Other technical experience at MDAC, and previously at Boeing, included performance of quantitative safety and reliability analyses of the short range attack missile, NERVA, the Shuttle and its payload applications program, the space station and associated nuclear power systems, the manned orbiting laboratory and its TITAN launch vehicle, and the SPRINT II missile.

Mr. Weatherwax has performed energy and risk analysis of fusion systems and nuclear reactor designs. At Princeton University, he modeled performance and cost properties of TOKAMAK fusion reactor concepts and associated power conversion technologies for commercial power plants CIRCA 2000. He was also coauthor of a nuclear physics assessment of the value of recycling spent reactor fuel in which the proponent's analysis was independently collaborated without reliance upon computer modeling. While employed by Science Applications, Inc., Mr. Weatherwax directed the probabilistic risk assessment (PRA) of the Hanford (nuclear) Reservation Purex Plant. He also managed the initiation of the PRA of a Swedish PWR under Swedish Government sponsorship.

Since forming SERA in 1981, Mr. Weatherwax has been steadily involved with assessment of reliability and risk of both nuclear and non-nuclear systems and materials. He has reviewed and evaluated the PRAs of the Indian Point and proposed Limerick and Shoreham light water reactor power plants. In 1983 (1984), Mr. Weatherwax testified before the Indian Point (Shoreham) Atomic Safety and Licensing Board regarding the probabilistic risk assessment of the Indian Point (Shoreham) Power Plant. His more recent studies have dealt with the proposed Shuttle-Centaur launch of the Galileo and ISPM spacecrafts. In another extensive reliability effort, Mr. Weatherwax and his staff performed a detailed assessment of the reliability and system effectiveness of an ultrasonic fatigue detection system for use in deep-sea oil drilling platforms. The analysis considered experimental results, and, drawing upon the GIDEP data base of observed failure rates for piece parts and subsystems, forecasted mature system reliability levels and accompanying uncertainty levels were projected.

Mr. Weatherwax's research and development interests in the area of probabilistic risk assessment have focused on the adequacy of existing fault-tree and event-tree methodologies for estimating low-probability event and representation of uncertainties in risk/benefit analysis. He contributed his insights in this regard to a 1985 NSF Peer Group review of the accuracy and utility of PRA for civilian LWRs. He was also involved in an AFWL project reviewing the PRA of the Space Shuttle/Galileo and International Solar Polar Missions. He also completed a comparative probabilistic failure analysis of alternative emergency power systems for the Shoreham Power Station in Long Island, New York.

D2-165 (Cont.)

Mr. Weatherwax's risk engagements associated with nuclear waste handling, transportation and disposal have resulted in his working on several EPA and DOE-related studies. The EPA studies dealt with high-level civilian nuclear waste and the long-term risks associated with deep burial in vitrified form. The DOE-sponsored studies dealt with both civilian and nuclear waste, with the processing and disposal of nuclear sludge in waste tanks at the Hanford Reservation being one area of focus. The civilian nuclear waste studies considered, in a generic fashion, various proposed options for disposing of the waste. Common-sense physical process screenings and comparative risk assessments were produced for ranking the various potential alternatives.

More recent energy system related studies have expanded Mr. Weatherwax's risk experience to include gas and electric transmission line hazards and line reliability and the transport and use of hazardous materials. As elements of these analyses, he has directed the modeling of hazardous materials releases, characterizing their source terms, tracking their potential dispersion patterns, and estimating levels of human exposure. The products of his work include: (1) a risk assessment that established the increased hazard associated with use of anhydrous instead of aqueous ammonia; (2) development and application of a methodology for estimating the risk of railroad hazards, including frequency and travel distance of derailed railcars; (3) estimates of risks associated with a proposed natural gas pipeline; and (4) development and application of a risk assessment methodology for estimating the risk from transportation of hazardous materials to a power plant site.

Mr. Weatherwax's experience in energy forecasting includes work done at Princeton University, U.C. Berkeley, and at the CEC (where he was Chief Energy Forecaster). During this time, he performed research involving formulating end-use microeconomic energy demand forecasting models and implementation of databases for use with various end-use forecasting models. He developed the first utility service area version of a residential end-use energy demand forecasting and associated load shape forecasting model.

As the Chief Energy Forecaster, he was responsible for forecasting electricity and natural gas requirements and peak loads of utility service areas used in determining the need for power plants within California. His duties included technical direction of about twenty-five postgraduate-level professionals in developing and implementing state-of-the-art microeconomic end-use models of energy consumption by fuel type and electric peak load by economic sector by utility service area. Other duties involved evaluating the cost effectiveness of conservation and alternative energy options and their potential energy impact.

EDUCATION

B.S., Engineering Science, California Institute of Technology, 1966
M.S., Aeronautics and Astronautics, University of Washington, 1968

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D2-165
(Cont.)

APPENDIX 2

QUEST
CONSULTANTS INC.®

June 17, 2009

Mr. Jim Fossum
Chairman
Sacramento Natural Gas Storage, Inc.
8031 Fruitridge Road, Suite B
Sacramento, CA 95820

Dear Mr. Fossum:

Quest Consultants Inc. has reviewed Appendix B – System Safety and Risk of Upset, a portion of a larger submission associated with the Sacramento Natural Gas Storage Project (SNGS Project), prepared by EDM Services, Inc., dated September 2008. Quest's review of Appendix B is limited to the use of the CANARY by Quest model used by EDM and the citations made to Quest publications.

Quest is the sole developer and licensor of the CANARY by Quest software. EDM purchased a license for the software in March, 2004. As part of the license agreement, Quest personnel provided a two-day training session for EDM's CANARY software users at that time. EDM has continued to receive updates to the CANARY software and currently use Version 4.3, the version referenced on the supporting documentation provided to Quest as part of this review.

D2-166

In analyzing the SNGS Project, EDM generally set up and executed the bulk of the pipeline release runs in a consistent and reasonable manner. However, there are several instances where incorrect or inconsistent assumptions have been made on the part of EDM personnel when developing the input data for the CANARY model that lead to significant overpredictions in the size of the potential hazard zone modeled. The following discussion will identify those assumptions (as they are listed in Appendix B) and discuss the effect of the assumptions on the modeling results.

It should be noted that this critique does not address any of the probability data used or risk calculations made by EDM regarding the SNGS Project. The review is strictly bounded by the modeling assumptions made by EDM and the subsequent impact on the consequence modeling results produced by the CANARY software.

D2-167

Text reprinted from Appendix B are presented below in italics.

Page Appendix B-8

3.1 Fire

- *8,000 btu/hr-ft^2 (25.1 kW/m^2) – 50 % mortality (CDE, 2007).*

D2-168

MAILING: P.O. BOX 721387 NORMAN, OK 73070-8069
SHIPPING: 908 26TH AVENUE NW, SUITE 103 NORMAN, OK 73069
TELEPHONE: (405) 329-7475 FAX: (405) 329-7734
E-mail: info@questconsult.com

D2-168 (Cont.)

It should be stated that this level of mortality is a result of a 30 second exposure.

- *3,500 btu/hr-ft^2 (11.0 kW/m^2) – Second degree skin burns after ten seconds of exposure, 15 % probability of fatality. This assumes that an individual is unprotected or unable to find shelter soon enough to avoid excessive exposure (Quest 2003).*

D2-169

This citation to Quest's CANARY by Quest User's Manual (Quest, 2003) is not correct. The CANARY User's Manual does list 3,500 Btu/hr-ft^2 radiant exposures for 10 seconds as causing second degree skin burns, but it does not state that such an exposure results in 15 % fatality. Quest cannot identify the source of this data point and cannot find a reference that would support its use.

These two citations are important since the definition of the hazard endpoint (in this case radiant flux levels produced by a flame) must be produced by a consistent set of conditions. For torch fires, this means that the length of time a flame is present (or a person is resident at a location) must match the exposure time that is associated with the radiant flux level. In other words, if you define the impact to a person after 30 seconds of exposure, the flame you modeled must exist for at least 30 seconds. Clarifying these radiant endpoints will aid in identifying the modeling approaches presented by EDM in Appendix B.

D2-170

Page Appendix B-9

3.2 Explosion

As noted earlier, natural gas does not explode unless it is in a confined space within a specific range of mixtures with air and is ignited.

This statement and much of the discussion immediately following it is correct. Unfortunately, later (in Section 6.3) this information is discarded and natural gas explosions are generated by assuming confinement is available.

D2-171

Page Appendix B-27

6.3 Release Modeling

In this section, various pipeline release scenarios are presented. The releases were modeled using CANARY, by Quest, version 4.2 software.

The intent of this statement is true. However, the latest version of CANARY, version 4.3 was actually used in the analysis as identified in the CANARY output files provided by EDM.

Several of the assumed modeling parameters in Table 6.3-1 (Draft EIR, Appendix B-27) are reviewed below. Several of the parameters, when combined, result in predictions of impact hazard distances that are impossible to achieve. Only those parameters that lead to a significant overprediction of the hazard or the generation of a hazard that cannot be achieved are reviewed below.

Table 6.3-1
Release Modeling Input

Parameter	Model Input
Contents	**Methane**
Wind Speed	2 meters per second (4.5 mph) for vapor cloud explosion modeling 20 mph for torch fire modeling
Stability Class	D – Pasquill-Gifford atmospheric stability is classified by the letters A through F. Stability can be determined by three main factors: wind speed, solar insulation, and general cloudiness. In general, the most unstable (turbulent) atmosphere is characterized by stability class A. Stability A occurs during strong solar radiation and moderate winds. This combination allows for rapid fluctuations in the air and thus greater mixing of the released gas with time. Stability D is characterized by fully overcast or partial cloud cover during daytime or nighttime, and covers all wind speeds. The atmospheric turbulence is not as great during D conditions, so the gas will not mix as quickly with the surrounding atmosphere. Stability F generally occurs during the early morning hours before sunrise (no solar radiation) and under low winds. This combination allows for an atmosphere which appears calm or still and thus restricts the ability to actively mix with the released gas. A stability classification of "D" is generally considered to represent average conditions.
Release Angle	45° above horizontal
Fuel Reactivity	Low – Most hydrocarbons have medium reactivity, as defined by the Baker-Strehlow method. Low reactivity fluids include methane, natural gas (98+% methane), and carbon monoxide. High reactivity fluids include hydrogen, acetylene, ethylene oxide, and propylene oxide.
Obstacle Density	Medium for 16-inch Segments Low for 12-inch Segments This parameter describes the general level of obstruction in the area including and surrounding the confined (or semi-confined) volume. Low density occurs in open areas or in areas containing widely spaced obstacles. High density occurs in areas of many obstacles, such as tightly-packed process areas or multi-layered pipe racks.
Flame Expansion	3 D – This parameter defines the number of dimensions available for flame expansion. Open areas are 3-D, and produce the smallest levels of overpressure. 2.5-D expansions are used to describe areas that quickly transition from 2-D to 3-D. Examples include compressor sheds and the volume under elevated fan-type heat exchangers. 2-D expansions occur within areas bounded on top and bottom, such as pipe racks, offshore platforms, and some process units. 1-D expansion may occur within long confined volumes such as hallways or drainage pipes, and produce the highest overpressures.

D2-171 (Cont.)

A few notes on the assumed parameters listed above.

1. Natural gas is not pure methane. Natural gas contains small amounts of other light hydrocarbons, ranging up to over five percent). The assumption that the pipeline gas is 100 % methane does not significantly affect the vapor dispersion or torch fire calculations, but it does have a significant effect on the vapor cloud explosion calculations.

D2-172

2. Using a low wind speed such as 2 meters per second (4.5 mph) does represent a worst-case condition for performing vapor dispersion calculations as the low winds allow the dispersing cloud to mix slower due to lower turbulence in the atmosphere.
Using 20 mph for the torch fire calculations does represent a worst-case condition for performing torch fire calculations as the high winds "bend" the flame downwind resulting in a longer distance to a specified radiant endpoint (maximizes the downwind radiant impact). D2-173

3. The use of stability class D for the low wind (2 meters per second) wind case when modeling the dispersion of gas from the pipeline does not result in a worst-case impact. If the worst-case dispersion condition were to be modeled, the F stability class would be defined. For the high pressure jet releases modeled, the differences between modeling the gas releases under D or F stability may not be too large, but the 2 meter/second; D stability combination does not result in a worst case. D2-174

4. The use of a 45 degree release angle is one of the three key assumptions made by EDM that produces incompatible results for the pipeline systems examined. As shown in Figure 6.3.1-1, the high pressure release of gas from a pipeline at an angle of 45 degrees from horizontal does not result, under any circumstances, in a flammable concentration of gas at or near grade level more than a few feet from the release point. Thus, there can not be any confinement or congestion associated with these releases. This is true for all the pipeline releases (45 degrees) and the well casing releases (90 degrees [vertical]). D2-175

5. Fuel reactivity is set to low. According to the Baker-Strehlow model in CANARY, methane is a low reactivity fuel. However, natural gas is not 100 % methane. The Baker-Strehlow model states if the fuel mixture contains more than 3 mol percent of medium reactivity fuels (e.g., ethane, propane, butanes) in the gas mixture, the fuel reactivity should be defined as medium. In this case, defining the fuel as low reactivity results in an underprediction of its potential explosion overpressure impact. D2-176

6. Obstacle density set to medium for 16-inch pipeline segments. If a 45 degree release angle is set for the pipeline releases and a 90 degree release angle is set for the well casing releases (see item 4 above), then the obstacle density in the volume occupied by the flammable gas is always going to be low. There is simply nothing directly above the pipeline that could induce any amount of obstruction that could enhance the flame speed should the gas ignite. The obstacle density for all the pipeline and well releases should be set to low. D2-177

Of the comments above, numbers 4, 5 and 6 have a significant affect on the explosion overpressure predictions made with CANARY as employed by EDM. For the simulations run by EDM, if the correct inputs were used, the maximum overpressure produced by the ignition of a natural gas plume would be 0.38 psig. It should be recognized that this maximum overpressure is located in the natural gas plume and decays rapidly as the distance from the flammable cloud increases. Add to this that the plume is elevated above grade and it would be highly unlikely that overpressures necessary to injure people via glass breakage in houses (defined as 0.20 psig in the Draft EIR, Appendix B-9) could be achieved at grade level. D2-178

This conclusion is supported by a wide range of experimental data and research projects. The vapor cloud explosion (VCE) calculations made with the CANARY software were made with the Baker-Strehlow model. This model is based on the premise that the strength of the blast wave generated by a VCE is dependent on the reactivity of the flammable gas involved; the presence (or absence) of structures such as walls or ceilings that partially confine the vapor cloud; and the spatial density of obstructions within the D2-179

flammable cloud.[1, 2] This model reflects the results of several international research programs on vapor cloud explosions and deflagrations, which show that the strength of the blast wave generated by a VCE increases as the degree of confinement and/or obstruction of the cloud increases. The following quotations illustrate this point.

> "On the evidence of the trials performed at Maplin Sands, the deflagration [explosion] of truly unconfined flat clouds of natural gas or propane does not constitute a blast hazard."[3] (Tests conducted by Shell Research Ltd. in the United Kingdom.)
>
> "Both in two- and three-dimensional geometries, a continuous accelerating flame was observed in the presence of repeated obstacles. A positive feedback mechanism between the flame front and a disturbed flow field generated by the flame is responsible for this. The disturbances in the flow field mainly concern flow velocity gradients. Without repeated obstacles, the flame front velocities reached are low both in two-dimensional and three-dimensional geometry."[4] (Tests conducted by TNO in the Netherlands.)
>
> "The current understanding of vapor cloud explosions involving natural gas is that combustion only of that part of the cloud which engulfs a severely congested region, formed by repeated obstacles, will contribute to the generation of pressure."[5] (Tests conducted by British Gas in the United Kingdom.)

D2-179 (Cont.)

Researchers who have studied case histories of accidental vapor cloud explosions have reached similar conclusions.

> "It is a necessary condition that obstacles or other forms of semi-confinement are present within the explosive region at the moment of ignition in order to generate an explosion."[6]
>
> "A common feature of vapor cloud explosions is that they have all involved ignition of vapor clouds, at least part of which have engulfed regions of repeated obstacles."[7]

D2-180

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[1] Baker, Q. A., M. J. Tang, E. Scheier, and G. J. Silva (1994), "Vapor Cloud Explosion Analysis." Presented at the 28th Loss Prevention Symposium, American Institute of Chemical Engineers (AIChE), April 17-21, 1994.

[2] Baker, Q. A., C. M. Doolittle, G. A. Fitzgerald, and M. J. Tang (1998), "Recent Developments in the Baker-Strehlow VCE Analysis Methodology." *Process Safety Progress*, 1998: p. 297.

[3] Hirst, W. J. S., and J. A. Eyre (1982), "Maplin Sands Experiments 1980: Combustion of Large LNG and Refrigerated Liquid Propane Spills on the Sea." *Proceedings of the Second Symposium on Heavy Gases and Risk Assessment*, Frankfurt am Main, May 25-26, 1982: pp. 211-224.

[4] van Wingerden, C. J. M., and J. P. Zeeuwen (1983), "Flame Propagation in the Presence of Repeated Obstacles: Influence of Gas Reactivity and Degree of Confinement." *Journal of Hazardous Materials*, Vol. 8, 1983: pp. 139-156.

[5] Johnson, D. M., P. Sutton, and M. J. Wickens (1991), "Scaled Experiments to Study Vapour Cloud Explosions." IChemE Symposium Series No. 124, *Hazards XI, New Directions in Process Safety*, Manchester, United Kingdom, April, 1991: pp. 67-85.

[6] Wiekema, B. J. (1984), "Vapour Cloud Explosions—An Analysis Based on Accidents, Part I." *Journal of Hazardous Materials*, Vol. 8, 1984: pp. 285-311.

[7] Harris, R. J., and M. J. Wickens (1989), "Understanding Vapour Cloud Explosions—An Experimental Study." The Institution of Gas Engineers, Communication No. 1408, 1989.

In the event of an ignition and deflagration of a natural gas in an open area, the overpressure levels generated are low and would not be expected to constitute an explosion hazard.

D2-180 (Cont.)

This assessment of the potential of natural gas releases from pipelines to produce inconsequential overpressures has been submitted to the California Department of Education (CDE) on several occasions when full quantitative risk analysis studies pipeline systems have been produced in support of the siting requirements for public schools. Quest has had numerous discussions with CDE on this subject and the final protocol documented in *Guidance Protocol for School Site Pipeline Risk Analysis – Volume 1 – User's Manual*[3] reflects the CDE's understanding that natural gas releases from pipelines do not produce a significant explosion overpressure hazard.

D2-181

The confirmation of this approach can be found in the natural gas pipeline release example contained in the CDE protocol document. The example is for a 30-inch natural gas pipeline operating at 400 psig. In this example (Section 4.5.3 of the CDE protocol document), the distances to a hazardous impact (defined as 1% mortality) is found to be 0 ft for a leak and 0 ft for a rupture. Thus, within the CDE protocol, the risk associated with natural gas explosion is found to be zero. This would be true for all natural gas transmission and distribution pipelines located in open areas.

D2-182

Page Appendix B-28

For the torch fires resulting from a full bore pipeline rupture, the mass flow rate after 1 second of the initial release was used. This release flow rate is somewhat less than the initial flow rate and somewhat greater than the flow rate after this period.

As stated previously, modeling the impacts from a fire require the duration of the flame to be consistent with the impact level defined. In other words, if the impact to a person is based on a 30 second exposure (e.g., second degree skins burns after 30 seconds exposure to 1,600 Btu/hr-ft^2 incident radiant flux), then the flame being modeled must exist for at least 30 seconds. Otherwise, the person cannot receive the 1,600 Btu/hr-ft^2 for the required 30 seconds. Using as an example the case identified by EDM as 16LFullE (full rupture of 1.5 mile 16-inch pipeline segment operating at 1,965 psia), the release rate of natural gas is shown in Figure 1.

D2-183

[3] URS Corporation (2007), *California Department of Education Guidance Protocol for School Site Pipeline Risk Analysis – Volume 1 – User's Manual.* Prepared for The California Department of Education, School Facilities Planning Division, Sacramento, California, February, 2007.

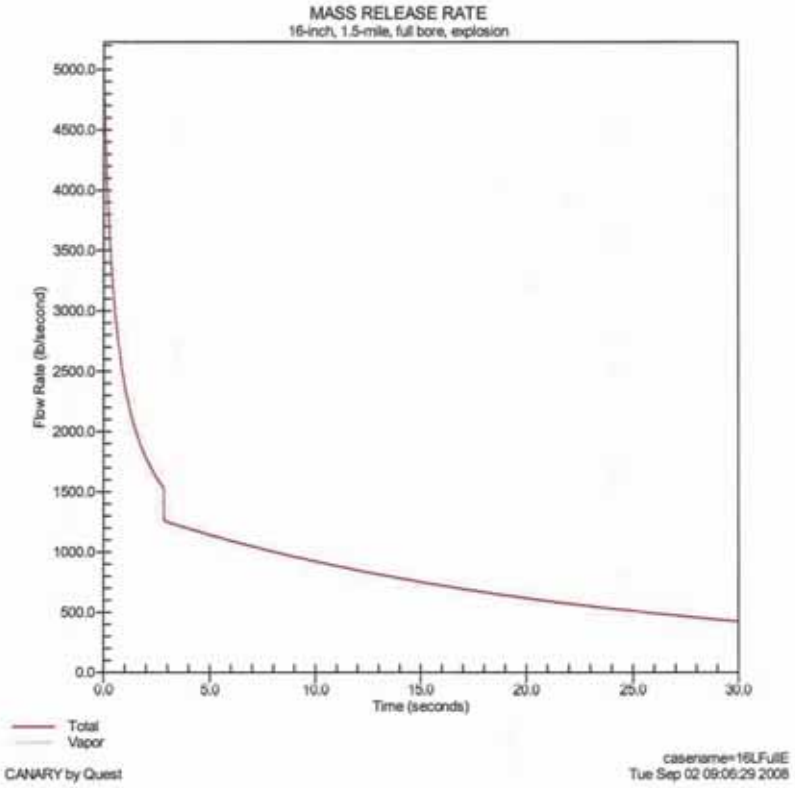


Figure 1

A review of the natural gas release rate in Figure 1 shows at the instant the pipeline ruptures; the exiting mass rate is greater than 4,500 lb/s. Since the pipeline segment is short, the pipeline depressurizes rapidly and the available natural gas inventory is exhausted out of the rupture. Approximately one second after the rupture occurs; the mass rate exiting the rupture has decayed to 2,372 lb/s. This rapid depressuring and deinventorying of the pipeline continues until the majority of the natural gas in the pipeline system is released. A review of Figure 1 shows the following natural gas flow rates at the identified times.

Time after rupture (sec)	Exiting natural gas flow rate (lb/s)
0.	4978.
1.	2372.
3.	1251.
5.	1143.
10.	924.
15.	753.
30.	426.

D2-183
(Cont.)

The CANARY User can select an exiting mass flow rate to enter into the torch fire model as EDM did, but it is then incumbent on the User to match the size and duration of the torch fire to the radiant endpoints chosen. In this case EDM's choice of a flame defined by a flow rate of 2,372 lb/s that only exists for one to two seconds, does not match the radiant impact criteria defined by a 30 second exposure. Thus, the choice of such a high natural gas flow rate as input to the torch fire model is incorrect for the radiant endpoints defined on page Appendix B-8 that range from a minimum of 10 seconds to over 30 seconds. D2-184

It should be noted that one of the outputs from the CANARY software is a definition of the mass flow rate of gas to be input into the torch fire model, provided by the release model. For the EDM case identified above, the CANARY output defines a natural gas flow rate of 587 lb/s as the rate to use in the torch fire model. This rate is based on the average rate of natural gas released over the first 60 seconds of release. D2-185

There are several reasons that the CANARY software has a built in 60 second average. D2-186

1. Not all pipeline failures result in instantaneous ignition. Some of the largest natural gas transmission failures have released gas for tens of seconds or minutes before igniting. Thus, using an average flow rate near the beginning of the release is a reasonable approximation.

2. At the moment of the pipeline failure, much of the energy in the first amount of gas released is consumed in removing the overburden from the pipeline. This gas does not behave as a jet or contiguous stream of gas making sustained combustion problematical. In order to have a sustained torch fire, the released gas must form a contiguous flammable zone.

This is not to say that natural gas flow rates other than a 60 second average cannot be used in CANARY. However, the chosen mass flow rate defines the size and shape of the flame, and that size and shape must exist for a period of time that matches the impact criteria defined by the user. Thus, if EDM did want to use the mass flow rate at one second as the torch fire input, then the endpoint criteria would have to be defined by a one or two second exposure to some level of incident radiation, not a 30 second exposure. D2-187

The end result of EDM's inconsistent modeling of torch fires following ruptures is that the radiant impact distances defined are significantly larger than what would occur and thus the consequences are overstated. It should be noted that the torch fires resulting from the smaller events modeled by EDM (e.g., 1-inch holes in the pipelines) were modeled using CANARY correctly. The exiting mass flow rates from holes in large diameter pipelines are fairly constant and longer lasting, thus making the time averaging approach easier to follow. D2-188

Page Appendix B-29

For a torch fire resulting from a full bore casing rupture, a stabilized mass flow rate of 2,700 pounds per second was assumed. This stabilized mass flow rate would be reached approximately 3 seconds after the release was initiated.

Modeling unregulated releases from a subterranean reservoir requires one of two approaches. The easiest approach is if the User knows the Absolute Open Flow (AOF) capacity of the reservoir. This is generally a known value and defines the maximum flow from the reservoir if there were no resistance to the gas flow exiting the formation. This value can then be used as an input to the CANARY program. D2-189

A second methodology is based on setting up the CANARY case input software to recognize that the reservoir is below the release point and have the program determine the release rate from the reservoir

(data required are the reservoir bottom hole pressure and temperature). EDM did not set this case up in this manner, thus the calculated flow rate does not represent the flow from one well.

D2-189 (Cont.)

Page Appendix B-29

6.3.1 Explosion Modeling Results

As discussed previously, natural gas generally does not explode, unless the vapor cloud is confined in some manner. The proposed 16-inch pipeline segments are surrounded by residential, heavy commercial, warehouse, industrial, and open space. The 12-inch pipeline segment is surrounded by very open, rural land and the I-80 Freeway corridor. As a result, there is insufficient confinement to cause a significant vapor cloud explosion within the atmosphere along the 12-inch segment. Along the 16-inch segment, should natural gas migrate into residences or other structures, the overpressures from an explosion within the confined space would be life threatening.

As discussed previously, there is no mechanism for the high pressure natural gas to "migrate" into structures along the pipeline right-of-way. At the exit of the pipe the natural gas is traveling at sonic velocity (395 meters/sec) and begins to rapidly mix with the atmosphere. When the centerline of the natural gas plume dilutes below the lower flammable limit (LFL), the gas is moving at 16.4 meters/sec (36.5 miles per hour). Thus, there is no flammable gas drifting into or toward any structure near the pipeline. The gas velocity and the release angle (45 degrees up from horizontal) eliminate any concerns of natural gas "collecting" in a structure.

D2-190

EDM may be confusing releases from high pressure natural gas pipelines with releases from low pressure (a few psig) lines that branch off of local gas distribution systems and lead to a residence. There have been instances where small, low pressure gas leaks migrate along the buried residential pipe and enter a house. This mechanism is not possible with high pressure lines since the force of the gas leaving the pipeline removes the overburden for any reasonably sized hole.

In summary, the consequence analysis calculations made by EDM using the CANARY by Quest software were generally set up in a consistent manner. However, several of the assumptions made by the people running the software result in impact distances for specific effects that are not reasonable. Some of these incorrect assumptions are simply due to a lack of understanding of the physics behind the modeling and should be easily corrected once reviewed. In short, the assumptions that need to be reviewed and changed are:

1. Torch fire mass rates – The mass rate defined as input to the CANARY model should be averaged over a period of time that either matches or exceeds the exposure time used to define the radiant impact effects. Thus, if EDM is going to define impacts by 10 or 30 second exposures to flame radiation, the mass release rate used to define the size and shape of the flame cannot be based on a single point value such as the release rate at 1 second after the pipe fails.

D2-191

2. Vapor cloud explosions – The correct parameters for the Baker-Strehlow explosion methodology when modeling outdoor natural gas explosion are as follows:

   Fuel reactivity = medium (natural gas containing less than 97 mol percent methane)
   Obstacle density = low (these jets form in the open air, there are no confining structures)

D2-192

Flame expansion = 3 D (the burning gas can expand in all directions)
Reflection factor = 2

When these parameters are employed in the CANARY model, the maximum overpressure achieved by the ignition of a natural gas cloud is defined as 0.38 psig. This overpressure value would be very near the flammable cloud, which is not near any ground level structures. Thus, minor building damage (e.g., glass breakage) may occur, but significant damage would not be expected.

D2-192 (Cont.)

3. Vapor cloud explosions – EDM has incorrectly assumed that high pressure jets of natural gas, directed upward (assumed 45 degree up from horizontal) can "migrate" into surrounding residences or building. This type of event is not possible in the system being evaluated as there is no mechanism available to collect drifting gas since the velocity of the gas at or above the LFL is moving at least 35 miles per hour.

D2-193

If EDM were to rerun the torch fire calculations using a mass flow rate and duration that matches the impact criteria and eliminate all of the vapor cloud explosion results, the consequence modeling predictions would more closely represent the potential impacts associated with a high pressure natural gas pipeline system.

D2-194

Please let me know if you have any questions.

Sincerely,

John B. Cornwell
Principal Engineer

nsm

John B. Cornwell
Principal Engineer
Quest Consultants Inc.®

EDUCATION

1978 — M.S., Mechanical Engineering
University of Texas, Austin, Texas

1975 — B.S., Chemical Engineering
University of Texas, Austin, Texas

EXPERIENCE

1989 - Present — Quest Consultants Inc., Norman, Oklahoma
Principal Engineer

Directs the company's hazards analysis and risk analysis efforts. Directs the use of the company's state-of-the-art phenomenological models to determine the extent of potential flammable/toxic/explosive hazards. Presents the technology behind the studies to corporate and regulatory groups.

Directs quantitative risk analysis studies (QRAs) involving:

- LNG import and export terminals
- LPG storage/marketing terminals
- LPG import terminals
- Refinery complexes
- Alkylation units (HF and H_2SO_4)
- Ammonia plants
- Transportation of toxic materials (road and rail)
- Pipeline networks (natural gas, LPG, ammonia, liquids)
- Exploration and production systems (oil and natural gas)
- Gas plants

Directs development of computer software, CANARY by Quest®, that provides analysis tools for the company. Oversees the use of public domain (e.g. DEGADIS, SLAB, LNGFIRE3) and special application software.

1985 - 1989 — Energy Analysts, Inc., Norman, Oklahoma
Principal Engineer

Directed the development of computer models to simulate the hazards associated with accidental releases of toxic/flammable materials. These models were contained in a commercially available software package named EAHAP.

Modeled the simulation of heavier-than-air gases and momentum jet releases of gases and aerosols. Directed the comparison analysis of several heavier-than-air gas dispersion models

D2-195

against the large-scale test data produced by the Thorney Island Trials, Desert Tortoise Ammonia Releases, and the Goldfish Hydrofluoric Acid Releases.

Directed numerous risk analysis/assessment studies using results of the consequence modeling and in-house risk modeling capabilities. Prepared and reviewed California RMPPs (Risk Management and Prevention Plans).

1984 - 1985 Los Alamos National Laboratory, Los Alamos, New Mexico
Staff Member/Research Scientist, Advanced Technologies Division
Security Clearance Level Q (DoE)

Evaluated advanced energy systems, including advanced fusion devices, liquid oxygen/liquid hydrogen turbogenerators, advanced photovoltaic systems, and conventional petroleum-based turbine systems.

1981 - 1984 Energy Analysts, Inc., Norman, Oklahoma
Senior Engineer

Directed the development of advanced simulation models for the dispersion of heavier-than-air vapors. Developed compatible thermodynamic systems and methodologies for predicting transient vaporization history of cryogenic fluids.

Directed development of a risk analysis model for use in conjunction with results of vapor dispersion and fire radiation analyses. The risk analysis model was employed in studies requiring the time-varying/site-dependent risk profile for petrochemical facilities and the surrounding area.

Evaluated transient fire hazards and the analysis of toxic combustion products.

1978 - 1981 University of Texas, Austin, Texas
Research Scientist, Center for Energy Studies

Developed a series of mathematical models to evaluate geopressured/geothermal resources along the Texas gulf coast.

PROFESSIONAL MEMBERSHIPS

American Institute of Chemical Engineers
Air and Waste Management Association
American Nuclear Society

PUBLICATIONS

Authored papers on hazards analysis modeling, risk analysis methodologies, project siting issues, and model-to-test data analysis.

D2-195 (Cont.)

APPENDIX 3

Golder Associates Inc.
18300 NE Union Hill #200
Redmond, WA USA 98052
Telephone: +1 425 883 0777
Fax: +1 425 882 5498
dersh@golder.com

Golder Associates

Our Ref: 08393247.001
10 June, 2009

Jim Fossum, Chairman
Sacramento Natural Gas Storage, LLC
8031 Fruitridge Road #B
Sacramento CA, 95820

Regarding: Draft EIR for SNGS Project

Dear Mr. Fossum:

Thank you for the opportunity to review the Draft EIR for the SNGS project. Based on my review of this document, I would like to provide the following observations.

1. The Draft EIR raises a concern regarding the effect of cyclic loading and unloading of gas pressures on cap rock integrity. Our June 2008 report, entitled "Evaluation of Cap Rock Integrity and Risk of Gas Release," demonstrated that cyclic loading and unloading are highly unlikely to result in cap rock degradation. The Draft EIR correctly states that our analysis is based on cap rock properties derived from cap rock and drilling logs and does not reflect laboratory tests. However, our analysis included a case in which the cap rock strength is significantly lower than would be expected from laboratory tests on cap rock shale at the Florin Gas Field. Our simulation of low strength assumed the following geomechanical properties:

   - Elastic (Young's) modulus (E) = $1.6 \cdot 10^6$ pounds per square inch (psi);
   - Unconfined Compressive Strength (UCS) = 2,000 psi; and
   - Tensile Strength = 50 psi.

   The geomechanical analysis described in our testimony did not identify any realistic cap rock failure modes even assuming these low strengths. Our testimony concluded that under cyclic loading conditions,

   - Deformations of the cap rock would be less than 1 inch,
   - Deformations would not induce irreversible straining in the cap rock, and
   - The stresses induced would be substantially below the failure envelope, even for the low strength shale that we conservatively assumed as a possible case in our analysis.

   The addition of strength testing of cap rock core samples would thus not be expected to change the results or conclusions of our geomechanical analysis. The recommendation of

D2-196

D2-197

strength testing of the cap rock is appropriate to confirm the analyses we have carried out, but does not in our opinion limit the conclusions, based on our geomechanical analyses, that cyclic loading and unloading are highly unlikely to result in cap rock degradation.

D2-197 (Cont.)

2. The Draft EIR states that pressures within the gas field may exceed the pressures of the original gas field (1,668 psi) by up to 8% (total of 1,804 psi). The Draft EIR also states that the lack of cap rock strength laboratory data raises concern that the cap rock strength to contain gas at the anticipated pressures has not been objectively demonstrated.[1] This statement reflects a misinterpretation of our analysis. As shown in our June 2008 report, the design gas pressures (both 1,668 psi and 1,805 psi) are substantially below the pressure necessary to cause hydraulic fracturing of the cap rock – even for the low strength value case considered in our geomechanical analysis.

D2-198

3. The Draft EIR concurs with our assessment that the leakage of gas is unlikely to occur. Nevertheless, the Draft EIR states that there is insufficient information to conclude that the migration of stored gas can be "categorically" eliminated. This statement may be true in the abstract. However, the theoretical likelihood of an increase in stress of 500 psi as a result of an earthquake occurring on the closest segment of the Great Valley fault zone is approximately 1 in 2 billion per year. The actual likelihood is significantly lower, as discussed below.

D2-199

4. The Draft EIR makes various assertions regarding the potential for gas to migrate into aquifers overlying the Florin Gas Field. At page D.6-23, the DEIR asserts that gas could migrate through existing cracks or faults, and that existing fractures or localized imperfections could dilate under proposed operating pressures. These concerns have no factual support. As discussed in Section 7.0 of our June 2008 report, the pressures necessary to reactivate faults are generally higher than the pressures required to fracture intact rock. In addition and as correctly noted in the DEIR, no faults are at present known to exist in the Florin Gas Field that could be reactivated.

   The DEIR's stated concern regarding potential seepage through localized imperfections reflects a misunderstanding of the analysis in Section 8.0 of our June 2008 Report. As explained there, seepage through localized imperfections would require pressures far in excess of those modeled by Ryder Scott assuming a constrained injection pressure of 1,650 psia. More particularly, we explained that no seepage will occur as long as reservoir pressures remain below 2,568 psi. We note that if localized imperfections existed in the Florin Gas Field's cap rock, it would not, given the original field pressure of 1,668 psia, have retained gas for several million years and during production.

D2-200

5. We agree with the Draft EIR recommendation HAZ-2ai for laboratory testing of cores and additional borehole tests. If testing is performed, and rock properties obtained from these tests indicate that the in-situ cap rock is stronger than the relatively weak cap rock

D2-201

[1] According to the June 30, 2008 letter prepared by Ryder Scott, and its accompanying exhibits and tables, the maximum pressure the reservoir will exert on the cap rock will never exceed approximately 1,805 psia, which is approximately 7.6 percent above the original pressure at the same locations. According to Ryder Scott's modeling work, those higher pressures would occur at only three discrete locations in the cap rock.

D2-202

values used in our geomechanical analysis, then the risk of cap rock failure should be considered statistically insignificant. This statement assumes that the operating pressures in the reservoir are kept within the stated design range.

D2-201 (Cont.)

We recommend that any laboratory tests of the cap rock core should be used to determine the unconfined compressive strength (UCS), tensile strength, elastic modulus, and permeability for a single core, sampled to minimize disturbance.

Test results showing unconfined compressive strength greater than 2,000 psi, an elastic (Young's) modulus (E) greater than 1.6×10^6 psi, and tensile strength greater than 50 psi should be considered as confirming that the assumptions used in our analyses were truly conservative.

D2-203

If the cap rock properties obtained from laboratory tests are less than these values, further geomechanical modeling should be performed to ensure that cap rock integrity is consistent with these lower values.

Laboratory tests should be performed on an intact rock core sample from one well taken from the shale cap rock. The representative nature of the core should be confirmed by comparing geophysical properties at the location of the core with the geophysical logs for the cap rock interval, particularly gamma and neutron logs. Core sampling should be carried out according to the sampling plans outlined by the testing laboratory or the following ASTM standards:

- ASTM D7012-07 Standard Test Method for Compressive Strength and Elastic Moduli of Intact Rock Core Specimens under Varying States of Stress and Temperatures"
- ASTM D 2938-95 "Standard Test Method for Unconfined compressive Strength of Intact Rock Core Specimens"
- RTH 114-93 "Proposed Method of Test for Gas Permeability of Rock Core Samples"

D2-204

Since the analysis of hydraulic fracturing depends on assumptions regarding in-situ stress, we also recommend that sonic-sidewall scanning to obtain in situ stress information be carried out for at least two wells through the cap rock.

6. As you requested, we have attempted to assess quantitatively the risk of rupture of the cap rock due to earthquake-induced stresses. As noted in our June Report, no existing information indicates that cap rock rupture is a realistic scenario, either through generation of a new fault through the cap rock, or by reactivation and propagation of a pre-existing fault. Geological data indicate that the cap rock has provided an effective seal for gas for several million years, including the last several hundred thousand years when the tectonic structure, and location and activity of faults was similar to the present day. There are, at present, no known faults that displace the Florin Gas Field, a conclusion with which the DEIR concurred. However, per your request we have carried out scoping calculations to quantify the probability of such a risk. Example results of this analysis include the following:

D2-205

D2-206

- A moment magnitude (M) 6.6 earthquake on the Great Valley fault Segment 4 (the closest known active fault to the site), is assigned a 480 year recurrence as estimated in the 2008 California earthquake hazard model. This M 6.6 earthquake could be expected to cause an estimated increase in stress of less than 1 psi in the cap rock at the site. This stress increase is essentially below the detection limit.
- To obtain an increase in stress of an estimated 500 psi in the cap rock at the site requires an earthquake on the Great Valley fault Segment 4 of approximately M 8.8. We have calculated the probability of such an earthquake at 1 in 2 billion per year, based on a rate and moment magnitude extrapolation using the USGS earthquake hazard database for California.

  However, this probability should be considered as an upper bound, because such a large magnitude earthquake is essentially impossible on the Great Valley fault because it has insufficient area to store and release the large amount of energy of an M 8.8 earthquake. Furthermore, current estimates indicate that the maximum earthquake size anywhere in California is probably M 8.3. An earthquake of this magnitude, if it occurs, is more likely to occur on large area, high-slip faults such as the San Andreas.

D2-206 (Cont.)

D2-207

Our initial calculations that indicate a very low probability of cap rock failure from earthquake-induced stresses are consistent with the geologic evidence. Repeated earthquakes have occurred on the major faults within the Coastal Ranges (e.g. San Andreas) and within the Sacramento Valley over at least the last 100,000 years at locations and rates similar to that observed during the last 200 years. There is no evidence these events have induced sufficient stresses or developed faults with sufficient displacements to compromise the integrity of the cap rock that stored gas prior to its extraction in the 1980s.

D2-208

Please do not hesitate to contact us if you need additional information.

Sincerely,
GOLDER ASSOCIATES INC.

William S. Dershowitz
Principal

APPENDIX 4

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5218 TELEPHONE (713) 651-9191
FAX (713) 651-0849

June 8, 2009

Mr. Jim Fossum
Sacramento Natural Gas Storage, LLC
8031 Fruitridge Road, Suite B
Sacramento, CA 95820

RE: Inquiries Concerning Geology in the Area of the Florin Gas Field (Winters Formation)

Dear Mr. Fossum:

I have prepared this letter in response to your recent inquiries.

Depth of Fresh Water

Fresh water is observed on the logs of the Florin Field wells above a measured depth of approximately 1300'. The fresh water interval is characterized by high resistivity in the sands and a flat SP curve throughout. The SP curve response indicates that the formation waters above 1300' have salinity approximately equal to the fresh water mud filtrate used to drill the wells; about 1700 ppm NaCl based on measurements on the log headers.

D2-209

Stratigraphic Description of Florin Field

The original productive gas sand at Florin Field is a series of stacked channel sands developed within the Winters Formation. Garrison (1993) describes the Winters Formation regionally in this part of the Sacramento Valley as "a prodeltaic shale" between the underlying Forbes Formation and the overlying Starkey Formation.

As we discussed previously in our letter of May 16, 2008, the upper part of the Winters Formation is the top seal for the Florin gas accumulation. In Florin Field this top seal consists of an impermeable shale unit that ranges in thickness from 173' to 238'. This thick shale seal trapped the natural accumulation of gas originally found in the field. This shale unit is also present in the TXO Northgate Beneficial #35-1 well northeast and updip of Florin Field; confirming that the top seal extends beyond the field boundaries.

D2-210

Overlying the sealing shale is the Starkey Formation. Garrison describes the Starkey as a thick sequence of about 1100' of fluvial-deltaic sands. On the log of the PG&E Florin #1 well the Starkey sands extend from 2458' to 3587' (1129' gross thickness). The interval has a high sand content and is salt water saturated. The sands are continuous across the Florin Field structure as well as updip in the TXO Northgate Beneficial #35-1 well.

Ryder Scott's previous reservoir simulation work using the anticipated operating conditions prescribed by Sacramento Natural Gas Storage (a maximum injection pressure of 1,650 psia at the well head and a field-wide maximum injection rate of 100 MMscf/d) has demonstrated that the pressure exerted on the thick shale top seal above the Florin gas sand will not exceed the original Field pressure by more than

D2-211

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7.6 percent. In addition, these high pressures would only occur briefly during the initial injection period and in a relatively small area. Ryder Scott anticipates that these modeled maximum pressures are well below the fracture pressure of the cap rock, and it is therefore unlikely that gas storage operations would cause a failure in the cap rock that would result in vertical migration of gas from the storage project.

D2-211 (Cont.)

However, at your request I have analyzed where gas would migrate to vertically in the highly unlikely event that the thick shale top seal above the Florin gas sand were to fail. Based on my analysis, escaping gas would most likely enter the Starkey sand and migrate updip and northeast away from the Florin area until a barrier is encountered. Escaping gas would preferentially follow a migration path within the Starkey sands rather than a vertical path to the shallow water table or the surface.

D2-212

Overlying the Starkey Formation is the regionally correlative "H&T Shale". This interval of impermeable shale is 88' thick on the log of the PG&E Florin #1 extending from 2370' to 2458'. This shale layer is present in all the wells in the Florin area and is expected to behave as an additional vertical seal.

Overlying the "H&T Shale" are 630' of interbedded fluvial sands and shales of the Mokelumne River Formation. The sand bodies in this interval are saturated with salt water. The individual sands and shales in the interval are correlative across all the wells in the Florin area. This interval extends from 1740' to 2370' on the log of the PG&E Florin #1.

The available logs for wells in the Florin area generally start below surface casing which is usually run to a depth of about 500'. The interval from 500' to 1300' consists of massive fresh water bearing sands. From 1300' to 1700' massive sands are found which contain fluids transitioning from the overlying fresh water to the saline water found within the Mokelumne River Formation.

D2-213

Common drilling practice is to set surface casing to a point deep enough to ensure the casing shoe will be in a formation strong enough to withstand the pressure of the mud column without fracturing. Wells at Florin, as elsewhere, are commonly drilled overbalanced, i.e. the pressure exerted by the drilling mud column on the formation is greater than the pressure within the formations drilled. In the Florin area therefore it is reasonable to infer that the entire stratigraphic column below 500' is competent enough to withstand the original reservoir pressure in the Florin gas sand.

D2-214

In summary, a sand / shale section more than 2400' thick separates the Florin Field gas reservoir from the base of fresh water at 1300'. Within this section are two regionally continuous shales and several locally continuous shales. Any and all of these shales could serve as vertical permeability barriers preventing any gas that might escape the Florin reservoir from migrating vertically through the stratigraphic column to either the fresh water table or the surface. One of the regional shales, the upper Winters, is a proven vertical seal that trapped the original gas accumulation in Florin Field. Further, any gas that might escape the Florin reservoir would be expected to preferentially enter the high quality, continuous sands of either the Starkey Formation or the lower Mokelumne River Formation rather than continue vertically to the water table or the surface. A cross section indicating these zones is included for your reference.

D2-215

Gas Migration Paths within the Florin Sand

You have also requested a discussion concerning possible lateral migration pathways of gas within the Florin Sand. Lateral migration of gas could potentially occur if the Field were injected with a volume of gas greater than it held initially (without failure of the cap rock). An attempt to fill the Field with more gas than it held at discovery might cause the excess gas to escape from the geologic trap. The Florin Gas Field originally produced approximately 8.3 Bscf from an estimated original gas-in-place of 13.7

D2-216

Bscf. Sacramento Natural Gas Storage proposes to inject no more than 7.5 Bscf to the field. Note that the total volume in-place anticipated during gas storage operations is less than the original volume, which suggests that the likelihood of lateral gas migration out of the storage area is remote. Furthermore, Ryder Scott's modeling efforts, under the previously described operating conditions, confirm that the likelihood any lateral migration out of the storage area is remote.

D2-216 (Cont.)

As we discussed in our testimony in October, 2008, the Florin Field reservoir is a combination structural / stratigraphic trap. In the updip direction (generally northeast) the trap is formed by the pinch out of the reservoir sands in the encasing impermeable shale. In the downdip direction, a structurally controlled gas / water contact was encountered by the original wells. As we also discussed earlier, gas production from the field allowed the aquifer to move updip into the area of the original gas reservoir. This was demonstrated by the Venada Lindsay #1 well. The Lindsay well was drilled in December, 1992, five years after Florin Field had stopped producing. The Lindsay well encountered the Florin reservoir water wet 64' above the original gas / water contact.

D2-217

Refilling the reservoir with gas will force the aquifer downdip towards its original position. This process is a repetition of the natural process that caused the gas accumulation to occur originally. Updip the TXO Northgate Beneficial #35-1 well found a correlative sand body to the Florin reservoir water wet. This sand is most likely the same unit as the lower wet interval found within the field. Gas escaping the Florin reservoir would most likely enter this lower unit and continue updip beyond the TXO well as it did when the reservoir originally filled with gas until it encountered a subsurface barrier or escaped at a distant outcrop. Thus, it is our assessment that gas would remain trapped within the Winters Formation.

D2-218

Thank you for the opportunity to perform this work. We look forward to continue working with you in the future. Please let us know if you have any questions or comments.

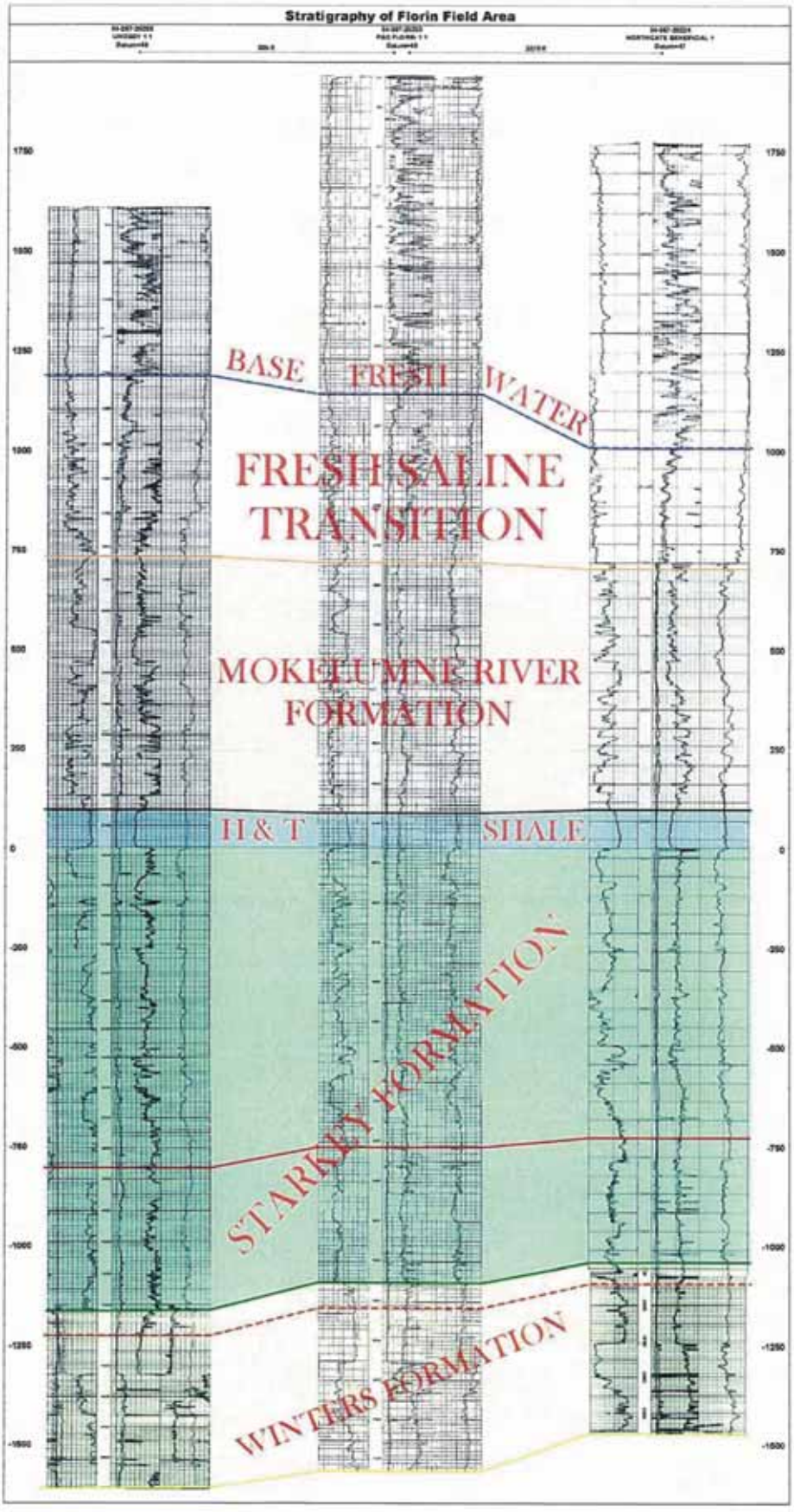
Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm License No. 1580

George F. Dames
Managing Senior Geologist

GFD/pl




Stratigraphy of Florin Field Area
BASE FRESH WATER
FRESH/SALINE TRANSITION
MOKELUMNE RIVER FORMATION
H & T SHALE
STARKEY FORMATION
WINTERS FORMATION

D2-219

APPENDIX 5

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5218 TELEPHONE (713) 651-9191
FAX (713) 651-0849

June 8, 2009

Mr. Jim Fossum
Sacramento Natural Gas Storage, LLC
8031 Fruitridge Road, Suite B
Sacramento, CA 95820

RE: Recommendations For Reservoir Monitoring

Dear Mr. Fossum:

The purpose of this letter is to provide Ryder Scott's recommendations regarding the subsurface monitoring of future gas storage operations in the Florin field. These recommendations are primarily provided for the purpose of monitoring and early detection of the unlikely but possible migration of gas outside the storage volume. Consideration is also given to the monitoring of water movement in the reservoir. Ryder Scott makes the following recommendations based on our past work for other gas storage clients, and other data available in the literature.[1, 2, 3]

D2-220

Ryder Scott recommends a well be drilled into the nearest porous/permeable zone overlying the caprock above the Florin field to monitor pressure. Any increase in pressure measured by this well would possibly indicate gas migrating through the caprock. Ideally this well would be located approximately in the center of the field (areally) and high on the anticline structure. A vertical well located at the proposed common wellhead site may be sufficient. This well could also potentially be used to monitor the pressure in any of the other zones located above the caprock.

D2-221

Ryder Scott recommends a well be drilled into the Winters formation in the Florin field to monitor reservoir pressure. This well should be located high on structure with a total depth above the gas water contact. Ideally the well should be located so as to be influenced as little as possible by the surrounding producers and injectors. The well should be kept at static condition with down hole measuring equipment to record reservoir pressure. Reservoir pressure is essential to maintaining an accurate accounting of gas inventory, and a rigorous inventory monitoring program is the best way to detect gas losses. The practice of inventory verification in gas storage refers to the comparison of actual gas volumes in the reservoir (pad gas + injected gas – produced gas) to theoretical gas volumes calculated from reservoir pressure using material balance methods. A prudent operator will continuously monitor measured (metered) injected and produced gas volumes and compare them with theoretical volumes based on observed reservoir pressures. Appreciable differences between actual and theoretical volumes indicates a potential loss of gas that may warrant further investigation. Ryder Scott also recommends that permanent down hole pressure measurement equipment be installed in some or all of the proposed production and injection wells. This equipment would be used to measure flowing pressures during operations and static pressures in the reservoir during shut-in periods.

D2-222

D2-223

[1] Katz, D. L.: "Monitoring Gas Storage Reservoirs," SPE Preprint 3287 (1971).
[2] Katz, D. L., et al: "Design of Gas Storage Fields," SPE Preprint 1059-G (1958).
[3] Tek, M. R.: *Underground Storage of Natural Gas*, Gulf Publishing Co., Texas (1987).

D2-220 (Cont.)

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It is our understanding that Sacramento Natural Gas Storage intends to drill a water disposal well. It is most likely that this well will be on the flank of the field in order to penetrate down into the aquifer that lies under the field. It would be beneficial to use this well to also monitor the movement of the gas-water contact in the field as gas is injected and removed from the reservoir. This may be accomplished either via a periodic cased-hole logging program or periodic pressure measurements at various depths to determine the transition from gas gradient to water gradient.

D2-224

Please do not hesitate to contact us if you have any questions or comments regarding these recommendations.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm License No. 1580

Bruce Palmer
Senior Petroleum Engineer

Dean C. Rietz, P.E.
Managing Senior Vice President

/pl

STATE OF TEXAS
DEAN C. RIETZ
70507
LICENSED
PROFESSIONAL ENGINEER

APPENDIX 6

ETIC ENGINEERING

June 17, 2009

Jim Fossum
Chairman
Sacramento Natural Gas Storage, LLC
8031 Fruitridge Road, Suite B
Sacramento, CA 95820

Dear Mr. Fossom:

The Draft Environmental Impact Report (Draft EIR) for the Sacramento Natural Gas Storage (SNGS) Project currently classifies the potential for migration of natural gas to potable aquifers as a significant and unavoidable Class I impact. Mitigation Measure H-8b of the Draft EIR describes a conceptual groundwater monitoring scheme. ETIC Engineering, Inc. has been requested to evaluate potential remediation options that would address methane impacts to groundwater.

D2-225

GEOLOGIC SETTING

The geologic setting of the SNGS Project area has been evaluated and described by Golder Associates, Inc. (Golder) (Golder 2008), by the Ryder Scott Company (Ryder Scott) (2009), and in the Draft EIR. The area is in the Sacramento Valley, South American Subbasin. The shale cap rock overlying the Florin reservoir is estimated to be approximately 3,500 feet below ground surface (bgs) and approximately 150 to 300 feet thick; it is overlain by the Starkey Formation and Mokelumne Formation, which are major depositional systems. Two distinct shale units are interbedded between the Starkey and Mokelumne Formations and above the Mokelumne Formation (Golder 2008). As described in the Draft EIR, groundwater in the subbasin occurs primarily in an upper aquifer, which may extend to approximately 300 feet bgs, and a lower aquifer, which may extend to approximately 1,300 feet bgs. Groundwater in both the upper and lower aquifers is suitable for municipal supply; groundwater in the upper aquifer is of generally higher quality. According to lithologic descriptions of previous Florin reservoir logs, deeper permeable zones are saturated with salt water (Ryder Scott 2009).

D2-226

CONCEPTUAL NATURAL GAS RELEASE SCENARIO

An evaluation by Golder (2008) concluded that there is negligible risk to cap rock integrity (assuming that the SNGS Project is operated in accordance with the pressure limitations

D2-227

assumed by Ryder Scott's June 2008 analysis (Ryder Scott 2008) and that laboratory testing confirms that the cap rock sealing the natural gas reservoir is at least as strong as the most conservative case Golder (2008) analyzed. Although the possibility of releases is extremely remote, pathways of potential releases from the storage reservoir are described below. Natural gas impacts above the cap rock would be expected to occur sequentially, with the portion of the Starkey Formation just above the cap rock being the first, and likely last, zone impacted.

D2-227

Natural gas that escapes from the reservoir must first enter the portion of the Starkey Formation immediately overlying the cap rock. Gas would be expected to migrate along preferential pathways (primarily bedding, jointing, and fractures – secondary porosity), thus migrating and dissipating laterally in permeable zones. Natural gas may potentially accumulate beneath less permeable zones and continue to migrate and dilute laterally, until a more permeable, continuous upward pathway is encountered. The Starkey Formation and overlying materials are major depositional systems, which include a series of interbedded units of higher permeability (sands) and lower permeability, including two distinct shale units as described above. Migrating natural gas, if released from the reservoir and not detected immediately above the cap rock, would need to follow an extremely tortuous path to reach shallower lithologic units and potable groundwater. A release of lower magnitude would dissolve into Starkey Formation groundwater, and upward migration would essentially cease.

D2-228

A catastrophic release is extremely unlikely – the confining pressure of the overlying saturated formation would physically limit the volume of gas released if a catastrophic event were to occur. The gas field is in an area of California that is not seismically active. Assuming that the most likely scenario of a catastrophic release would be an earthquake of sufficient magnitude to breach and offset the cap rock, the probability of such an occurrence is extremely remote – as calculated by Golder (2009), the theoretical probability is 1 in 2 billion per year, and necessary magnitude may not actually be achievable under tectonic conditions in California.

D2-229

The most likely pathway for vertical migration may be a well borehole, assuming the unlikely breach of the well seal at the cap rock. In addition to encountering multiple opportunities for lateral migration as described above, however, the upward migration of escaped gas along the well borehole would be blocked by the cement seal from approximately 1,500 feet bgs to the surface proposed for newly installed wells. Furthermore, wells previously abandoned in the Florin Gas Field were also sealed at depths beneath the fresh water aquifer and bracketing the cap rock, according to the California Division of Oil, Gas, and Geothermal Resources

D2-230

specifications, and the Draft EIR recognizes that the potential for adverse environmental impacts as a result of natural gas migration along the path of such wells is not significant.

D2-230 (Cont.)

REMEDIATION APPROACHES AND FEASIBILITY

Possible Methane Impacts Above the Cap Rock

As described above, natural gas impacts to groundwater above the cap rock would be expected to occur sequentially, with the portion of the Starkey Formation just above the cap rock being the first zone impacted. In the extremely unlikely event that natural gas were to escape the Florin Gas Field, eventually, through a series of also extremely unlikely events, some portion of the natural gas might make its way to the shallow water-bearing zones above a depth of 1,500 feet. Contact of natural gas with groundwater would result in some portion of the natural gas dissolving in the water. The following section describes how these impacts could be remediated utilizing proven technologies.

D2-231

Risk Associated with Natural Gas Impacts

Natural gas consists primarily of methane (with a pipeline quality in the PG&E transmission system of typically approximately 95 percent or greater). There are no health effects from ingesting water in which methane gas is dissolved. However, methane gas can become harmful if it escapes from water (at concentrations greater than 28 milligrams per liter [mg/L]) and builds up in poorly ventilated or confined areas, causing an explosion or asphyxiation hazard. Methane typically forms an explosive mixture in the air at concentrations of 5 to 15 percent by volume.

D2-232

A smaller fraction of natural gas is composed of C2 to C5 alkanes, also considered to be of low toxicity. There is an even smaller fraction (<0.06 mole percent) of natural gas that is composed of hydrocarbons C6 and greater. This fraction may include constituents such as benzene, toluene, ethylbenzene, and xylenes (BTEX) (<1 part per million in natural gas) that have toxicities greater than those of the lower alkanes. Of these compounds, benzene is considered to be the most toxic, with a California Maximum Contaminant Level established for drinking water of 1 microgram per liter (µg/L). These compounds are less volatile and more soluble in groundwater than methane and therefore would even more likely be preferentially

D2-233

dissolved in the deeper non-potable groundwater as the gas approaches the surface, making the BTEX compounds even less likely than methane to migrate to potable water sources.

D2-233 (Cont.)

Under What Conditions Would Remediation be Necessary

Starkey Formation: Small releases within the Starkey Formation pose no threat of impact to the shallow water-bearing zone. There is a large assimilative capacity in this zone that will limit migration if a release is detected and stopped. If it is determined that natural gas does not migrate to a shallow water-bearing zone, remediation of escaped gas would not be necessary because there would be no direct exposure route to humans and no adverse effects of the release.

D2-234

Shallow Water-bearing Zone: A substantial prolonged release, under extremely remote circumstances, might lead to an impact of shallow groundwater. If this were to occur, the water-bearing zone that would be initially impacted would be the lower saline portion of the shallow water-bearing zone. This water is unusable for human consumption, as well as for most other uses. Natural gas impacts to this zone alone would not necessarily require remediation of the groundwater because there would be no direct exposure path to humans.

D2-235

Potable Water-bearing Zone: In the extremely unlike event that a potable aquifer were to be impacted by methane, any requirement of remediation would be dependent on concentration. If the concentration in water were greater than 28 mg/L, remediation would likely be required because methane readily transfers from the dissolved to a gaseous state at concentrations greater than this level. Dissolved methane concentrations less than 10 mg/L are generally considered safe (Water Systems Council 2007). Dissolved methane levels between 10 and 28 mg/L would likely require monitoring to ensure that they did not increase, but they would not necessarily require remediation.

D2-236

Remediation of Saturated Zone Impacts

Groundwater within any of the saturated zones can readily be remediated by the methods described below. In general, the deeper the zone to be remediated, the more costly the remedial effort becomes. The increase in cost is due to the increase in cost of installing deeper wells and operation and maintenance issues associated with poor water quality below the potable zone.

D2-237

As described above, there is a small fraction (<0.06 mole percent) of natural gas that is composed of hydrocarbons C6 and greater, which may include constituents such as BTEX. The remedial technologies described below are also effective for treating the BTEX constituents.

Any released natural gas would dissolve in groundwater as encountered. BTEX has a water solubility that is more than an order of magnitude greater than methane; therefore, the concentration of any of these compounds in escaped gas would decrease as the gas migrates. As a result, any gas that ultimately made its way to the shallow water-bearing zones would likely be composed mainly of methane, with some fraction of gaseous alkanes.

D2-238

Remediation of dissolved methane can take two possible forms. The first is remediation of water in the aquifer to reduce its overall concentration to acceptable levels. The other is protection of operating wells from explosive hazards and reduction of methane in water that has been withdrawn from the aquifer to eliminate any remote possibility of explosion and asphyxiation hazards for domestic and municipal use.

D2-239

Aquifer Remediation Methods

<u>Air Sparging:</u> Air sparging is a groundwater remediation technology that is typically applied to remove volatile dissolved constituents, such as BTEX. It is a common and proven technology that has been used for aquifer remediation for more than 20 years. This technology, although not typically applied to methane remediation (because the need for such remediation is uncommon), would be very effective when applied to methane because methane is volatile and relatively insoluble in water, moving preferentially to air in a sparging system.

The technology is applied in-situ and may require that the liberated methane be captured by means of vapor extraction and treated by flaring or reuse by SNGS if the concentration is sufficiently high or if the volume of unsaturated soils above the aquifer are not sufficient to absorb/disperse the methane.

Air sparging involves the injection of contaminant-free air into the subsurface saturated zone, enabling a phase transfer of hydrocarbons from a dissolved state to a vapor phase. The air is then vented through the unsaturated zone.

D2-240

Air sparging is most often used with soil vapor extraction (SVE). When air sparging (AS) is combined with SVE, the SVE system creates a negative pressure in the unsaturated zone through a series of extraction wells to control the vapor plume migration. This combined system is called AS/SVE.

D2-240 (Cont.)

The scope and size of the air sparging system would depend on the aerial extent and volume of water impacted. Depending on the locations of the source of the methane, the impacted water, and possible receptors, the air sparging system can be configured to maximize performance and minimize costs.

Groundwater Pump and Treat: A common remedial strategy to deal with contaminated groundwater is to extract the impacted water and treat it at the surface prior to discharge or reinjection. This is referred to as conventional pump-and-treat (P&T) remediation. P&T systems have been used to treat groundwater aquifers since the early 1980s.

P&T systems are designed to: (1) hydraulically contain and control the movement of contaminated groundwater; (2) remove dissolved contaminants to comply with clean-up standards and thereby "restore" the aquifer; or (3) a combination of these objectives.

D2-241

Hydraulic containment of dissolved compounds by pumping groundwater from wells has been demonstrated at thousands of sites. Recovered groundwater is usually treated at the surface using methods selected to remove the contaminants of concern. In many cases, hydraulic containment systems are designed to provide long-term containment of impacted groundwater at the lowest cost by optimizing well locations and by minimizing pumping rates.

The aboveground treatment that would be used to remove methane from the extracted groundwater would most likely be air stripping. The effluent from the air stripper will be a permitted source and will likely have to be abated by the use of a thermal oxidizer.

The scope and size of the P&T system would depend on the aerial extent and volume of water impacted. An alternative to implementing a stand-alone independent system, which would extract, treat, and reinject the groundwater, would be to deliver the treated water to the nearest water purveyor.

In-situ Treatment Using Sulfate-Reducing Microbes: Hydrocarbons can be used as a food source by bacteria in aquifer systems. Methane concentrations in groundwater have been

D2-242

observed to be reduced by natural biological processes. Dissimilatory bacterial sulfate reduction has been observed to oxidize methane under anaerobic conditions, resulting in the reduction of methane concentrations (Van Stempvoort et al. 2005). This process may naturally take place if methane were to enter a shallow water-bearing zone. Although this process would not be promoted in a potable aquifer through the addition of sulfate or bacteria, the process may naturally occur, resulting in the gradual reduction of methane concentration.

D2-242 (Cont.)

Well Hazards

Wells used to extract groundwater for domestic and municipal use would be at risk of an explosion hazard of methane in the extremely unlikely event that the potable water zone were to become impacted at concentrations of methane approaching 28 mg/L. The hazard would be easily mitigated through the use of standard well venting methods.

D2-243

Domestic Use Groundwater Treatment

Single households or small water systems would have to implement treatment measures for methane in the extremely unlikely event that the methane concentration in extracted groundwater were to exceed a concentration in the 15 to 20 mg/L range. Commercially available treatment systems are available for use by single households or small water systems. Because methane occurs frequently in potable water aquifers at concentrations ranging up to 60 mg/L or more, these types of systems are common. These systems aerate the water and vent the methane to the atmosphere before water enters the household. A public outreach effort would serve to notify well owners that might be impacted.

D2-244

Municipal Water Supply Impacts

The groundwater in the area of the SNGS Project is of a quality that requires only disinfection. This is a closed process that does not affect the methane concentration. To provide water safely to its customers, the municipal water purveyors would need to remove the methane prior to distributing the water.

Treatment of the water by the purveyors would involve removal of the methane by air stripping. The stripper would most likely be a pretreatment process done prior to disinfection. Removal of methane to acceptable concentrations can be easily achieved because

D2-245

methane is volatile and relatively insoluble. Air stripping of water, as with air sparging described earlier, alters the natural equilibrium of dissolved gasses and ions primarily because carbon dioxide is also removed by the process. Stabilization of the water chemistry may also be required. Any BTEX components that may also be present in the groundwater would also be removed by the air stripper with minor design changes and abatement.

D2-245 (Cont.)

Remedial Objectives

There are no known significant health effects from ingesting water in which methane is dissolved. The objective of remediation is to reduce the methane in groundwater to levels that make it safe for any domestic or industrial use. The remedial goal would likely be to reduce the groundwater concentration to below 10 mg/L.

D2-246

SUMMARY AND CONCLUSIONS

A conceptual gas release and migration scenario has been evaluated in which natural gas impacts to any shallow water-bearing zone are extremely unlikely. If the monitoring network successfully detects a release so that it could be stopped within a short time frame, the tortuous route of vertical migration and assimilation capacity of the formation would make the potential for impacts to the potable water aquifers correspondingly even more remote.

D2-247

In the extremely unlikely event that a prolonged release occurred and impacted the potable water aquifer, commonly used and proven groundwater remediation technologies applicable to aquifer remediation and conventional wellhead treatment could be used to lower the impacts to an acceptable level and readily avoid any adverse impacts to human health and safety. These remedial technologies are especially applicable to methane impacts because methane is easily removed from groundwater. These technologies are also applicable to the more soluble and less volatile compounds that might also be present.

D2-248

Although there are no known significant health effects from ingesting water in which methane gas is dissolved, natural gas impacts to the potable aquifer may adversely affect municipal water purveyors, small water supply systems, and single-family water systems. Commonly used aeration systems are available to address potential safety hazards. Air stripping can be used as a pretreatment technology to remove methane from groundwater prior to any normal treatment process currently in use. This technology is often used by municipal water purveyors

D2-249

to remove odors from water as part of a treatment process. The technology is especially applicable to methane removal because of the relatively low water solubility and high volatility of methane.

D2-249 (Cont.)

Please contact us if you have any questions.

Respectfully submitted,



Douglas Oram, Ph.D.
Principal



Terry Winsor, P.G.
Senior Geologist

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ETIC ENGINEERING

DOUGLAS E. ORAM, Ph.D.
Principal and Technical Program Manager

EXPERTISE

Program, Project Management	Senior Technical Review
Soil and Groundwater Remediation	Subsurface Investigations
Remedial Effectiveness Evaluations	Testing of New Remedial Technologies

EDUCATION

Ph.D., Organometallic Chemistry, University of California, Davis, 1989
B.S., Chemistry, University of California, Davis, 1983

EXPERIENCE

Mr. Oram has over 20 years of experience in the design, implementation, and evaluation of remedial engineering projects and subsurface investigations, 2 years of experience in analytical chemistry, and 6 years of experience in synthetic chemistry and process development. He is the author of more than 30 technical publications and co-author of *Selection of Representative TPH Fractions Based on Fate and Transport Considerations*. Mr. Oram is involved in the technical direction of all projects requiring remedial action.

Technical Publications and Guidance Documents: Mr. Oram is co-author of an MTBE and TBA Natural Attenuation Demonstration Guidance Manual that was developed from a basin-wide evaluation of MTBE and TBA impacted sites in Orange County, California. Stable carbon isotope analyses were performed at each site as a direct measurement of MTBE biodegradation. A tiered approach was presented that allows for varied methods of demonstrating MTBE and TBA biodegradation based on site and regulatory complexity.

Mr. Oram is co-author of the Total Petroleum Hydrocarbon Criteria Working Group Series, Volume 3 titled *Selection of Representative TPH Fractions Based on Fate and Transport Considerations*. Mr. Oram developed a method of dividing the spectrum of TPH compounds found in hydrocarbon mixtures into a small number of fractions having similar transport properties to simplify modeling and risk assessments. The same process was also applied to chlorinated hydrocarbon, PNA, and PCB compounds.

Remedial Design and Implementation: Mr. Oram has prepared or directed the design and implementation of soil, sediment, and groundwater remedial actions at over 100 sites located in Alaska, California, North Carolina, and New York. Remedial designs have covered all common technologies and a number of newer or innovative in-situ oxidation and reduction technologies. Remedial technologies implemented:

In-Situ Chemical Oxidation Methods	Pump and Treat
Zero Valent Iron Reactive Barriers	Soil Vapor Extraction
Reductive Dechlorination	Monitored Natural Attenuation
Excavation and Dredging	Landfill Capping
Bioventing	Air Sparging
Dual-Phase Extraction	

Defense Manufacturing Facilities (Rockwell Collins Site Portfolio) Solvent and metals impacted former and operating large acreage defense manufacturing facilities:

Former Kaiser Aerotech Facility, San Leandro, California
Remedial Investigation and Site Characterization – Directed soil matrix, soil vapor, and groundwater investigations in support of a comprehensive remedial investigation for the large acreage former Kaiser Aerospace site in San Leandro, California. Having successfully negotiated a focused scope for these investigations with the regulatory agencies, ETIC generated the data needed to evaluate potential risks to human health and the environment, to develop risk-based cleanup levels, and to evaluate remedial alternatives for the site.

Kaiser Electroprecision, Irvine, California
The site is an active defense manufacturing facility. Historical chlorinated solvent and petroleum hydrocarbon contamination had been documented by past consultants, including a general definition of the extent of a

groundwater plume. Remedial activities conducted by past consultants at the site had included over 10 years of groundwater extraction and 1 year of soil vapor extraction, and testing of enhanced bioremediaton.

Upon successful negotiation of a roadmap to site closure with the RWQCB, ETIC conducted a focused source area investigation, resulting in lateral and vertical delineation of a limited solvent and petroleum hydrocarbon source area. Aggressive remedial efforts were implemented to meet the client's desired goal of rapid closure. Efforts were conducted during active facility operations, and included excavation of the source area soil and installation of a permeable wall with zero-valent iron (ZVI) reactive media downgradient of the excavation footprint for the degradation of inaccessible dissolved contaminants, with short-term post-remediation groundwater monitoring of the permeable wall, which demonstrated successful subsurface cleanup. ETIC submitted the remedial action report and case closure was received within 1 year.

Former Kaiser Fluid Technologies, Charlotte, North Carolina
This site is a former defense manufacturing facility. Historical chlorinated solvent and petroleum hydrocarbon contamination had been documented by past consultants, without identification of the source. The State would have required indefinite groundwater monitoring. Closure above stringent groundwater use standards can only be achieved via a multi-step regulatory variance process. Mr. Oram directed the efforts to identify the source, implement remediation to the extent practicable, and apply for state variance, allowing the client's desired goal of closure without long-term groundwater monitoring. Efforts included excavation of the source area soil and installation of a permeable wall with zero-valent iron (ZVI) reactive media downgradient of the excavation footprint with short-term post-remediation groundwater monitoring of the permeable wall, which demonstrated successful subsurface source area cleanup. Groundwater modeling efforts were also conducted to provide additional support that plume movement was limited.

ETIC negotiated closure at this site instead of redesign and installation of a second pump and treat remediation system or application of in-situ chemical oxidation. Each of these alternatives had a low probability of closing the site. Over $1,000,000 had been spent on installation and O&M of a groundwater extraction system previous to our company becoming involved with the project. Our company conceived of and negotiated closure of the site with only 3 months of monitoring after conducting a limited excavation and installation of a Permeable Reactive Barrier (PRB). Closure of the site resulted in releasing $2,000,000 of funds held in escrow.

Air Force Center for Environmental Excellence (AFCEE) - Project Engineer for the development and production of Remedial Designs for five Operable Units at Eielson AFB, Alaska. Based on the results of the RI/FS, pilot tests and treatability studies were conducted at representative sites. Based on the pilot tests and studies, remedial designs were produced and implemented for each of the Operable Units. The remedial designs included product recovery and bioventing systems at fuel release sites, in-place containment and monitoring at solvent drum burial sites, capping of a municipal landfill on the base using consolidated ash from the base power plant, dredging of a 2-mile length of stream impacted with PCBs, and monitoring for the implementation of natural attenuation. Contaminants encountered and treated were solvents, fuels, pesticides, herbicides, PCBs, PNAs, and metals. All remedial actions were designed to operate through the Alaskan winter.

MTBE and TBA Investigation and Remediation - Project Director for numerous investigations and remedial actions throughout California focused on delineating the extent of migration of MTBE and TBA within the vadose and saturated zones and applying appropriate remedial technologies to achieve pre-negotiated remedial action goals. Feasibility analyses and decision tree methods were used to determine if remedial action was required and, if so, the most effective extraction and treatment methods for site conditions.

MTBE and TBA Treatment Technology Evaluation - Project Director for feasibility analysis and field testing of MTBE and TBA treatment technologies. Prior to applying treatment technologies at a large group of sites, an economic and feasibility analysis was conducted to identify technologies applicable to the treatment of MTBE and TBA. Based on the feasibility study analysis, five of the most promising technologies were field tested using split streams of extracted water from a representative site. The results of the technology evaluation were used by major oil companies to aid in the selection of MTBE and TBA treatment technologies.

TBA Plume Conceptual Model - Directed a study for the American Petroleum Institute to develop a comprehensive conceptual model for the occurrence, transport, and fate of TBA.

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ERRG

Terry R. Winsor, PG

Senior Project Manager

Discipline/Specialty
- Geology
- Remediation

Education
- M.B.A. Finance, 1989, St. Mary's College of CA
- Graduate work in mineral exploration, 1976 -1977, Stanford University
- B.S. Applied Earth Sciences, 1974, Stanford University

Registrations
California Professional Geologist, 4719, 1990

Safety/Certifications
- 40-hour HAZWOPER Training
- 8-hour HAZWOPER Supervisor Training
- 8-Hour Refresher Training (1919.120)
- 10-Hour Occupational Safety & Health Administration Training in Construction Safety and Health

Summary of Qualifications

Mr. Winsor has distinguished himself as a project manager in remediation, environmental consulting, and mineral exploration. Since 1987, Mr. Winsor has managed projects for state, federal, and industrial clients in remediation and environmental consulting. The projects range in scope from preliminary environmental assessments through remedial actions that have resulted in closure. He has managed investigations, feasibility studies, and the design, construction, operation, maintenance, monitoring, and optimization of remediation systems. Mr. Winsor is currently a Senior Project Manager for Engineering/Remediation Resources Group, Inc. (ERRG) for whom he manages projects in remediation, operation, maintenance, and monitoring. Mr. Winsor is the client/program manager for work done under partnering agreements for Pacific Gas and Electric Company (PG&E) and also provides technical guidance and senior technical review of documents for a variety of clients and projects.

Relevant Experience

Engineering/Remediation Resources Group, Inc., (ERRG) October 2006 to Present, Senior Project Manager/ Senior Geologist

Post-Closure Operation and Maintenance at the Geothermal, Inc. Landfill, Middletown, CA

Mr. Winsor manages post-closure operation, maintenance and monitoring that ERRG does for PG&E under the direction of AMEC Geomatrix. Non-routine tasks include grading in borrows, planting new trees, installation of new water supply wells, and construction of litter fences. Routine tasks include removal of boron salt accumulations, minor repairs on the landfill cap, weed control, and litter and debris abatement for fire control/prevention. ERRG also monitors depths to groundwater and the quality of groundwater and surface water quality. Semi-annually ERRG prepares a data transmittal report for submittal to the Water Board.

Remedial/Removal Actions at former Chico-1 Manufactured Gas Plant (MGP), former St. Helena MGP, Former Oakland-1 MGP Former Potrero MGP, Former Merced MGP, and Former SAC-1 MGP for PG&E, Northern California

Mr. Winsor provides technical assistance for PG&E and its consultant partners on remedial and removal actions at former manufactured gas plants throughout northern California. ERRG placed a permeable asphalt and concrete cap over exposed soils along the easement for a high pressure gas line at the Oakland Gas Load Center (former Oakland-1 MGP) and excavated and disposed of soils at former Chico-1, former St. Helena, and former Merced MGPs. Mr. Winsor managed the removal of shallow monitoring points at the former Potrero MGP for AMEC Geomatrix; using a tracked excavator, ERRG pulled the casing from each monitoring point and backfilled them with grout. Mr. Winsor reviews monitoring reports and work plans for former SAC-1 MGP.

Consulting Services for PG&E

Mr. Winsor provides a variety of consulting services for PG&E. Services include the completion and certification of remedial actions at a third party site in southern California and at a former substation in Bakersfield, California. Other services include review of technical reports and work plans and management of groundwater monitoring at service centers and former substations and MGPs.

Remedial Action for Operable Unit 2, former Nacimiento Copper Mine, Cuba Ranger District Santa Fe National Forest, New Mexico and Operation, Maintenance and Monitoring of Former USTs

Project and Program Management

Mr. Winsor manages the construction, operation, and maintenance of a semi-passive alcohol-enhanced bioreactor to remediate groundwater at the former Nacimiento Copper Mine in the Santa Fe National Forest near Cuba, New Mexico. Bacteria in the bioreactor reduce sulfates in groundwater contaminated with sulfuric acid and dissolved metals to hydrogen sulfide; the hydrogen sulfide reacts with dissolved metals in the influent water to precipitate as sulfides in the settling pond. Treated water is discharged to a nearby stream. ERRG and its consultant are responsible for compliance with rigorous discharge and water quality standards.

Pacific Gas and Electric Company [Under Contract Through Corestaff - Future Presence Colonial Commerce, and ACT1], April 2003 to October 2006, Project Manager

As a [contract] project manager for Environmental Services – Site Remediation, Pacific Gas and Electric Company (PG&E), Mr. Winsor managed remediation projects for the real estate portfolio. Before PG&E sold surplus properties, PG&E assessed each for environmental liabilities and remediated them for unrestricted use. Mr. Winsor also managed the remediation of former manufactured gas plants (MGPs). Work scopes ranged from Phase I environmental site assessments through full remedial actions at former and active facilities. Facilities included substations, service centers, and MGPs. Mr. Winsor also managed investigations and remedial actions on third party sites where PG&E had been identified as a potentially responsible party. Mr. Winsor prepared budget and reserve estimates for internal PG&E use and worked actively with consultants and contractors to cost effectively identify and correct environmental contamination for which PG&E was responsible. Contaminants varied from metals such as lead and arsenic to organic residuals from the manufacture of gas, such as coal tar and lamp black. Through the cooperation and oversight of designated lead agencies, primarily the Department of Toxic Substances Control (DTSC), the Regional Water Quality Control Board, and county agencies, Mr. Winsor secured letters and certificates of no-further-action (NFA) required for four former substations, two former service centers, and one former manufactured gas plant. To accomplish this work Mr. Winsor oversaw and worked closely with consultants and contractors, tracking and reporting progress and costs and reviewing technical project documents and reports.

Independent Contractor/Consultant, Senior Project Manager for ETIC Engineering Principal Geologist, Delivery Order Manager, and Business Unit Manager for MWH (formerly Montgomery Watson), and Senior Geologist and Business Unit Manager for EA Engineering Science and Technology(EA ES&T), June 1987 to March 2003

Mr. Winsor managed the investigation and remediation of organic and inorganic contaminants for state, federal, and industrial clients on projects that ranged from soil gas surveys to the design/build of large-scale groundwater pump and treat systems. Mr. Winsor also managed business units for MWH and EA ES&T for which he was responsible for managing and mentoring technical staff, for profit and loss of the business units, and for developing new business opportunities.

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APPENDIX 7

Environmental hazards posed by the Los Angeles Basin urban oilfields: an historical perspective of lessons learned

G.V. Chilingar · B. Endres

Abstract Urban encroachment into areas historically reserved for oil and gas field operations is an ever-present problem within the Los Angeles Basin. The recent frenzy in real estate development has only intensified what can be characterized as a conflict in land usage. Subsurface mineral rights are severed from surface ownership, often resulting in developments being approved without adequate consideration of the underlying oil and gas field consequences. Also, surface operations are frequently co-located within residential areas without consideration of the health and safety consequences of emissions of toxics to air. This paper presents a review of the environmental, health and safety hazards posed by urban oilfield operations, with an emphasis upon the lessons learned from the "L.A. Basin Original Urban Oilfield Legend" (see Castle and Yerkes 1976; Denton and others 2001; Endres and others 2002; Kouznetsov and others 1994; Katz and others 1994; Schumacher and Abrams 1994; and Schoell 1983). The Los Angeles Basin has provided the authors with one of the largest natural laboratories in the world for studying the consequences of these issues. The results presented are part of a long-term research program based upon the application of geoscience and petroleum engineering principles in obtaining a fundamental understanding of the root causes of the environmental hazards posed. Topics addressed include: (1) vertical migration of gas to the surface along faults and improperly completed or abandoned wellbores (e.g., due to poor cementing practices), (2) subsidence caused by the fluid production and declining reservoir pressures, (3) soil and groundwater contamination resulting from historic oil and gas field operations, and (4) air toxics resulting from surface operations. A number of case histories are discussed that illustrate the seriousness of the problem. A clear case is made for the urgent need for closer coordination and education by the petroleum industry of the local government planning departments. These departments have the principal role in determining land use policies, acting as the lead agency in performing environmental site assessments (e.g., under the California Environmental Quality Act), and in establishing mitigation measures for dealing with the long-term environmental hazards. This paper establishes prudent practices on the part of oilfield operators for the monitoring and mitigation of these hazards.

Keywords Los Angeles oilfields · Gas migration · Toxic gases (hazard) · Subsidence · Earthquakes · Methane

Received: 28 November 2003 / Accepted: 9 August 2004
Published online: 26 October 2004
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G.V. Chilingar (✉)
Department of Civil and Environmental Engineering,
University of Southern California, Los Angeles, CA 90089, USA
E-mail: gchiling@usc.edu
Tel.: +1-323-932-8369

B. Endres
Consultant, 101 S. Windsor Blvd., Los Angeles, CA 90004, USA

Introduction

The environmental hazards posed to the urban development by oil and gas field operations are numerous. These hazards must be properly evaluated and mitigation measures implemented in order to protect public safety. These hazards are caused by gas migration along faults, subsidence caused by the fluid removal with consequent formation of faults and fractures, and by improperly maintained wellbores.

The Los Angeles Basin, California, has over seventy oilfields that underlie extensive urban development. This setting has provided the authors an opportunity to study the long-term environment consequences of this mixed usage. These environmental hazards are not unique to the Los Angeles Basin, but relate to fundamental principles of gas migration, along faults and fracture zones, subsidence, and outgassing of oilfield gases that must be properly evaluated. This paper provides a detailed insight into these hazards, as well as lessons learned from the numerous

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DOI 10.1007/s00254-004-1159-0

disasters that were not properly planned for. Methods for reducing risks and mitigation of hazards are discussed. Four aspects of these environment hazards are presented:

1. Oilfield gas migration into the near-surface deposits and aquifers.
2. Soil and groundwater contamination from upward migration of oilfields fluids, mainly gases.
3. Subsidence caused by oilfield fluid withdrawal and declining reservoir pressures.
4. Outgassing and release of air toxics from the oil- and gas-field operations.

These issues are interactive and must be evaluated in combination. Ignoring these issues could result in substantial legal liability upon the oilfield operator and upon those responsible for the public safety. Subsidence also reslults in the formation of faults and fracture zones, which are avenues for the migration of gases.

Gas migration in oilfield settings

The Los Angeles Basin has been plagued with numerous oilfield gas seeps that continue to present serious explosion and health risks to the residents. Oilfield gases have a propensity to migrate to the surface along faults and poorly completed and/or abandoned wellbores. Furthermore, the upward migrating gases will accumulate in the near-surface collector zones, often trapped and concealed within the permeable gravel and sand lenses.
The lower explosive limit (LEL) of the oilfield gases (composed primarily of methane) is approximately 5% by volume when mixed with 95% by volume of air. This translates into a serious explosion and fire hazard, especially where the gas is capable of migrating into a confined space such as a room or an electrical vault. In the Los Angeles Basin many homes and commercial structures have been constructed directly over old oil wells that have not been properly sealed, and no mitigation measures have been taken to seal out the seeping gases.

The March 24, 1985, Ross Department Store explosion

The first clear recognition of a very serious problem with oilfield gases migrating to the surface and causing an explosion hazard was the March 24, 1985, incident in the Fairfax area of Los Angeles which demolished the Ross Department Store and injured over 23 people (Cobarrubias 1985). Escaping oilfield gases burned for days through cracks in the sidewalks and within the parking lot surrounding the store located at 3rd Street and Ogden Drive, directly across the street from the Farmer's Market. Also, large quantities of gas were detected migrating to the surface under the Hancock Park Elementary School located on Fairfax Street near 3rd Street.

Near-surface soil gas studies revealed that the highest concentrations of gases were aligned in an elliptical pattern with the semi-major axis having an exact alignment with the Metropolitan Number 5 Slant Well operated from a nearby drilling island. A review of production records revealed that this well consistently produced the largest gas volumes of any operational well from the underlying Salt Lake Oilfield. Eventually, well records were obtained that revealed that the well casing had developed leaks as a result of corrosion holes located at a depth beginning at approximately 366 m, and extending deeper (Endres and others 1991; Khilyuk and others 2000).
Gas pathways to the surface included the 3rd Street Fault, that surfaced at the Ross Store location, and an old abandoned vertical well identified on the Division of Oil and Gas map for the area as Well Number 99. A vent well drilled into the parking lot of the Ross Store discovered a large pocket (collector zone) of trapped oilfield gas at a depth of approximately 15 m (Fig. 1). This collector zone had sufficient porosity and permeability to serve as a temporary trapping mechanism for the large quantities of upward migrating gases from the leaking wells to build to pressures of approximately 1.8 kg/cm^2. A clay layer served as a trapping mechanism until its threshold pressure was exceeded. Permanent soil gas probes were installed to a depth of approximately 4.6 m in order to perform ongoing monitoring of the upward migrating gases (Fig. 2).
Detailed gas fingerprinting, primarily utilizing isotopic gas characterization, was instrumental in providing 100% scientific proof (Fig. 3) that the explosion and fire were caused by the underlying Salt Lake Oilfield operations (Schoell and others 1993). Also, further investigation revealed that the gas seeps at the nearby La Brea Tar Pits result from upward migration of gases from the Salt Lake Oilfield along the 6th Street Fault (Jenden 1985). The 6th Street Fault slopes downward to the north and intercepts the oilfield reservoir at the location of the Metropolitan Number 5 well. Production Zone (viz., a very prolific gas zone). Gas fingerprinting has confirmed that the gas seeps at the La Brea Tar Pits match the leaking gases that caused the Ross Department Store explosion (Jenden 1985).

The City of Los Angeles methane ordinance

Following the Fairfax explosion and fires in 1985, the City of Los Angeles adopted a methane ordinance that was incorporated into the City of Los Angeles Building Code, Chapter 15, titled "Methane Seepage District Regulations." The stated purpose is for the control of methane intrusion emanating from petroliferous formations. These regulations apply largely to new construction, the boundaries of which are defined in the code, but are coincident with the boundaries of the Salt Lake Oilfield.
Existing commercial structures, including the Hancock Park Elementary School, were required to install gas detectors. These requirements for gas detection in existing buildings, however, were limited to the commercial

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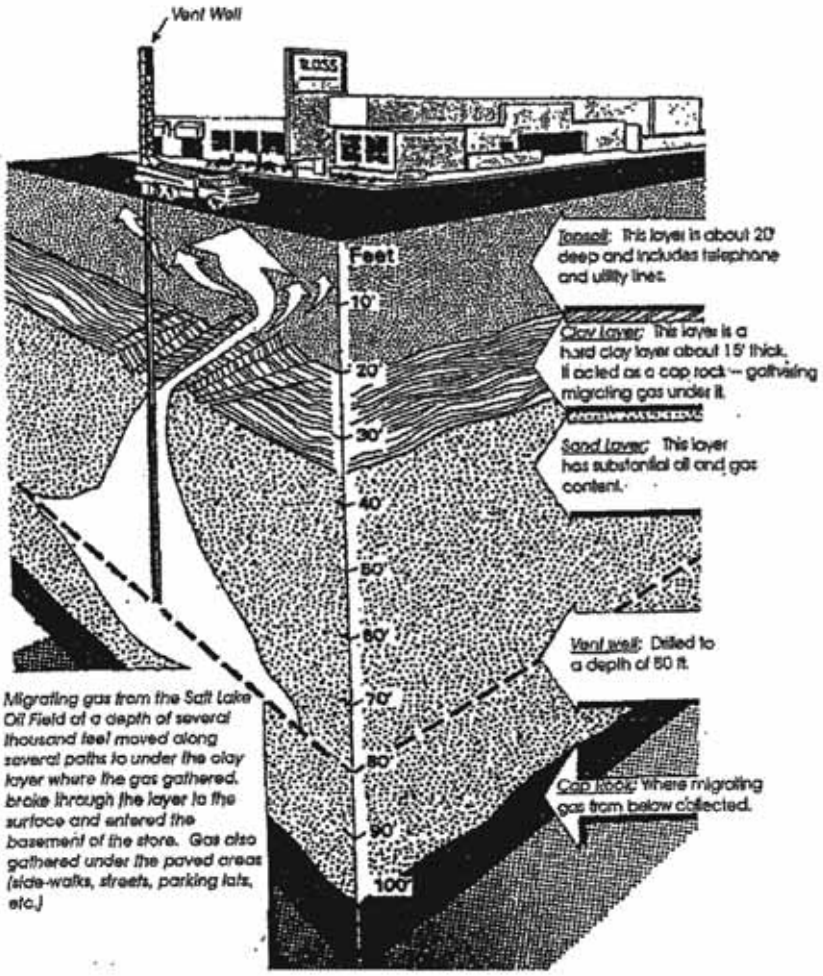


Fig. 1
Schematic showing how gas entered the basement of the department store and the surrounding area (modified after an article by George Ramos and Ted Thackery in the Los Angeles Times 1985; Illustration by Michael Hall

buildings in the immediate vicinity of the Third Street and Ogden explosion site. Additionally, these commercial establishments were required to share the weekly monitoring expenses associated with the permanent soil gas probes that are depicted in Fig. 2. Unfortunately, the Anthony No. 1 gas well (see Figs. 1, 2), that was installed to vent gas from the underlying formation, became plugged in the 1989 time period. Namely, the weekly monitoring of the soil probes failed to provide advanced warning of a near-disaster on February 7, 1989.

The near disaster of February 7, 1989

On the morning of February 7, 1989, a pedestrian who was walking by the Gilmore Bank building, located on the north side of Third Street and across the street from the 1985 explosion site, observed gas bubbling through the ground in a planter box. The fire department was called, which led to the discovery of area-wide gas seeps emerging from below the sidewalks and streets, a near repeat of the 1985 incident, but without an explosion.

It was discovered that the Anthony vent well had become plugged at the perforated intervals of the permeable sand zone depicted in Fig. 1. This condition was aggravated by the ground water movement existing at the depth of vent well.

The response team soon recognized similarities to the 1985 explosion and fires, and the area was immediately cordoned off to prevent ignition and explosion of the gas. In the wake of this near disaster, the City of Los Angeles undertook a second task force study. There is overwhelming scientific evidence that the gas accumulations were the direct result of ongoing oil and gas production, and leaking oil wells.

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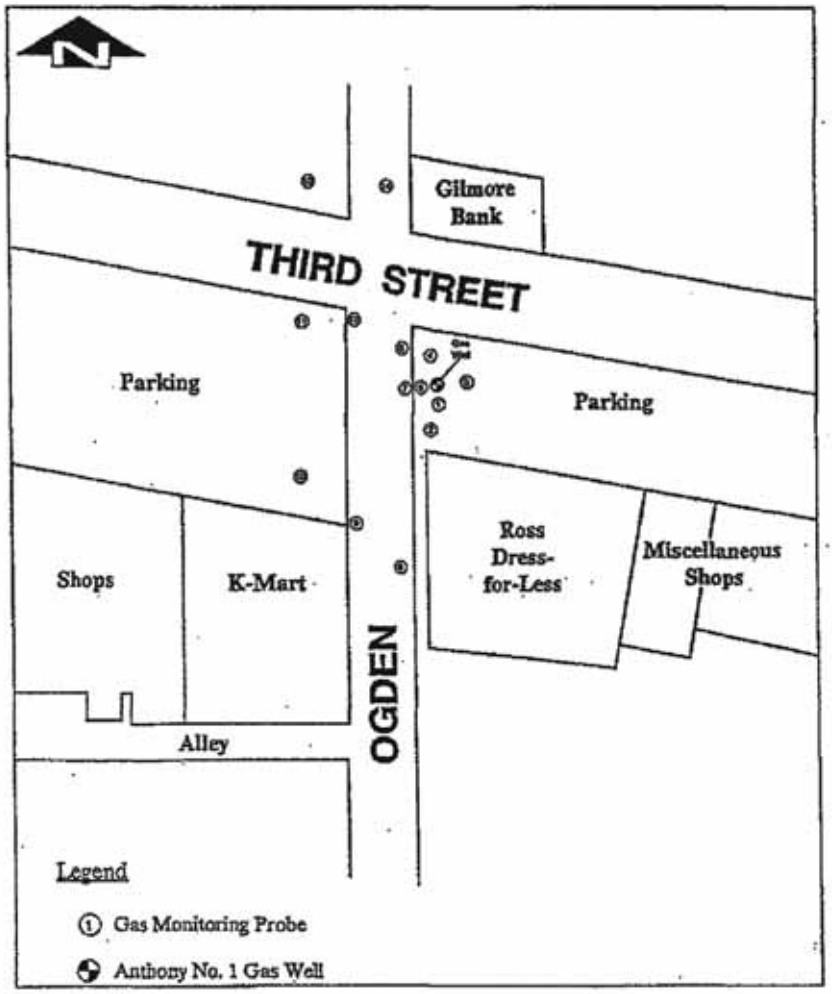


Fig. 2
Probe location map; 3rd St. and Ogden Drive, Los Angeles, California (courtesy of City of Los Angeles Fire Department)

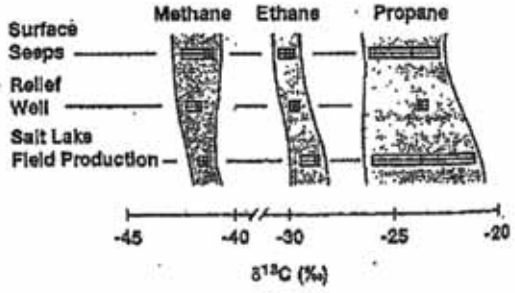


Fig. 3
Carbon isotopic fingerprinting of gas leaking from reservoir to the surface (after Schoell and others 1993, Fig. 6, p. 7)

Well records clearly demonstrate that the Metropolitan No. 5 well had developed serious corrosion leaks in the well casing. These leaks were ongoing, and caused large quantities of oilfield gases to leak into secondary collector zones below both the explosion site and under the Hancock Park Elementary School.

The gas fingerprinting experts (Schoell and others 1993; Jenden 1985) showed the match between the field production gases and the gas from seeps at the surface (Fig. 3).

There is an increased risk of a similar incident occurring somewhere else within approximately 70 oilfields within the Los Angeles Basin. The most important lesson to be learned from the Fairfax explosion is the need to carefully evaluate the integrity of the many old oil wells in the Los Angeles Basin that can serve as the primary source and/or the pathways for the oilfield gases to migrate to the surface. The authors have confirmed this enormous hazard by evaluating hundreds of documented well leaks, and identifying the causes of the leaks. Virtually all well leaks can be traced to the poor

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well completion and/or abandonment procedures (e.g., poor cementing practices).

Environmental hazards of oil well leaks

Wells that were drilled and completed many years ago are subject to ongoing corrosion and deterioration of both the steel casings and the cements.

Gas intrusion into cemented wellbores and the resultant leakage to the surface and porous formations below the wellhead have been persistent problems in the oil and gas industry for many years (Marlow 1989). Pressure and temperature cycling on the cement bonding characteristics, an acute problem in the gas storage industry, can give rise to shoe leaks and loss of bonding in the annular cement. To help quantify the annular leakage problem in gas storage wells, a survey was prepared and sent to the members of the American Gas Associations Pipeline Research and Storage Reservoir Supervisory Committees. The survey attempted to determine the magnitude of the annular leakage problem.

Tests showed that even when the most up-to-date cement types and techniques are used, leakage can and will occur in a significant number of cases (Marlow 1989 pp. 1147, 1148). For example, in a study of 250 casing jobs over a 15-month period with new cements, 15% of the wells leaked (Watters and Sabins 1980). Accordingly, the poor cementing and completion practices, typical of the many old wells located in the Los Angeles Basin, are giving rise to very serious environmental problems associated with gas leakage to the surface in the annular space, as discussed herein.

Numerous fields have accumulations of hydrogen sulfide that will eventually destroy the integrity of both the steel and cement relied upon to provide protection against gas migration, including abandonments performed to the current standards of the DOGGR. The corrosive conditions of hydrogen sulfide are well known, and have defied engineering solutions (Craig 1993).

Ongoing seismic activity in the Los Angeles Basin is also a major factor in contributing to a well integrity problem. For example, the 1971 Sylmar earthquake was responsible for causing well blowouts in the Fairfax (Salt Lake Oilfield) area (Khilyuk and others 2000).

Wilshire and Curson gas seep

A very serious gas seep at the intersection of Wilshire and Curson (directly across the street, and south of the La Brea Tar Pits) was discovered in 1999. This required the City of Los Angeles to install a vent pipe on the south-west corner of this intersection in order to direct the oilfield gases into the air above the adjoining three story commercial building. The odors from the gas emitted from the vent pipe are noticeable throughout the area.

The commercial office building to the immediate east of this seep location was experiencing gas migration through the foundation and into the building. A ventilation system is operating 24 h/day within the subterranean parking structure of that building in order to mitigate against the risk of an explosion.

Historical records of the area, reviewed by the writers, revealed that an old abandoned well had been drilled near the location of the seep. However, the high-density commercial development in the area has prevented finding the well.

South Salt Lake oilfield gas seeps from gas injection

In January 2003, serious gas leakage problems were discovered in the South Salt Lake Oilfield, located in a residential area near the Fairfax area (viz., in the vicinity of Allendale and Olympic Boulevard). The oilfield operator had been injecting natural gas into the South Salt Lake Oilfield for approximately two years, under elevated pressures to enhance recovery. However, gas began leaking to the surface along abandoned and poorly completed wellbores. In fact, the Division of Oil and Gas records reveal that numerous wells were drilled before the official records were maintained. Accordingly, the existence and abandonment status of some of these wells is unknown. High-density urban development, largely of apartment buildings has occurred directly over many of the old wells.

Montebello underground gas storage

The partially depleted Montebello Oilfield was converted into an underground gas storage operation. Natural gas was transported into the field through interstate pipelines and injected under high pressure (exceeding 105.6 kg/cm^2) into the 8th Zone at a depth of approximately 2,286 m. This storage gas was discovered leaking to the surface along old wellbores that had been drilled in the 1930s era. In some instances, homes had to be abandoned and torn down to provide access to drilling rigs in an attempt to repair and/or reabandon old wells. Studies revealed that the cement plugs used in well abandonment and the integrity of the well casings and cements were not adequate to seal off the high-pressure storage gas from migrating along the wellbores to the surface. This facility had to be abandoned because of the gas leaks. However, it will take many years to deplete the gas to pre-storage conditions.

These examples indicate the importance of a systematic examination of how wells leak, and the dangers posed by allowing residential construction to occur directly over old wells. If each well leak is evaluated in isolation of the long history of problems in an area, the true dangers may not be recognized.

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Playa Del Rey underground gas storage

The Playa del Rey Oilfield, located in the Marina del Rey area of the Los Angeles Basin, was converted to an underground gas storage operation in the 1942 time period, and has been operated in that manner ever since. The Venice Oilfield adjoins the area to the immediate north. The gas storage reservoir has been leaking into the adjoining Venice Oilfield since the early years of operation (Riegle 1953). There are over 200 old and abandoned wells throughout this area, including wells that had to be abandoned in order to accommodate the construction of the Marina del Rey Boat Harbor (Fig. 4). For example, some old wells are located directly below the main channel that connects to the Pacific Ocean. Numerous gas seeps have been observed by the authors of this paper within the boat harbor, and within the Ballona Flood Control Channel that bisects the area and extends eastward along the old Los Angeles Riverbed alignment.

The Los Angeles River was responsible for depositing a massive gravel layer that extends eastward providing a highly permeable zone for leaking oilfield gases to collect and migrate easterly, including under the influence of tidal forces. The gravel zone begins (viz., below surface sediments) at a depth of approximately 15 m (referred to as the "15-meter Gravel") and extends to a depth of several hundred feet. This gravel zone interconnects many of the old wells in the area, and serves to conceal the identity of wells that are experiencing the worst leakage. Gas fingerprinting has established that the leaking well gases match the gases seeping to the surface along the flood control channel and into the surrounding residential areas.

This gravel zone is saturated with oilfield gases, which becomes additionally pressurized during the heavy rains as a result of the shallow aquifer being recharged. Surface gas seeps become very pronounced because of this pressurization, and can be observed bubbling through standing water during rains. Probes placed into the 15-meter Gravel Zone have measured gas flow rates as high as 20–30 l/min. Also, drilling rigs have experienced blowouts as a result of encountering the high-pressure gas zone when penetrating to 15 m.

These examples, including the Ross Department Store explosion and vent well histories, reveal the importance of understanding the underlying hydrology in the identification of hazardous oilfield gas seeps to the surface (also see Toth 1996). These studies have confirmed that the underlying permeable aquifers can act to conceal the true magnitude of the gas migration hazards. Accordingly, soil gas studies must include determination of the magnitude of dissolved oilfield gases contained in the near-surface aquifers. This may include multiple zones, requiring the use of deep soil probes.

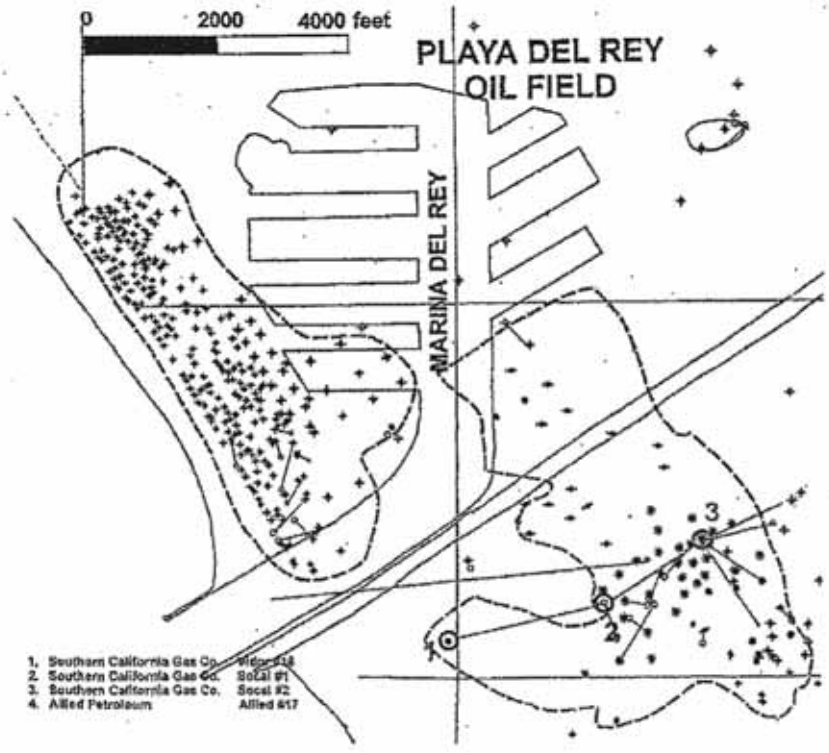


Fig. 4
Playa Del Rey oilfield (courtesy of Jack West, petroleum geologist, Fullerton, California)

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A review of well abandonment records for the Playa del Rey and Venice oilfields has revealed very serious leakage problems. Leakage within the annular space between the casing and drillhole, because of poor cementing (see above), is a serious problem. Most of the wells depicted in Fig. 4 were drilled in the 1930s, before prudent cementing practices were used. For example, wells that had been abandoned as recently as 1993—to make way for housing developments—were found to be leaking when excavations were begun for the actual construction. In each case, homes were constructed directly over the old wells after minimal efforts were taken in an attempt to reseal the wells. Because of the small lots and high-density construction, there will be no room for reaccessing the wells using conventional drilling rigs.

Most of the construction in the Playa del Rey and Venice oilfield areas has failed to provide gas detection or other mitigation measures (e.g., as required by the Methane Ordinance) in order to deal with these gas migration hazards. For example, the underground gas storage operations at Playa del Rey involves injection of storage gas under high pressure (approximately 120 kg/cm^2). Gas inventory studies (Tek 1987) have shown that leakage is directly proportional to the reservoir pressure maintained for gas storage (see Fig. 5). This raises serious questions about the appropriateness of locating gas storage fields in highly populated urban settings, especially where many homes have been built directly over poorly-abandoned wells. It is paramount that a fundamental understanding of how wells leak and proper procedures for monitoring are developed. Gas storage pressures are typically selected by

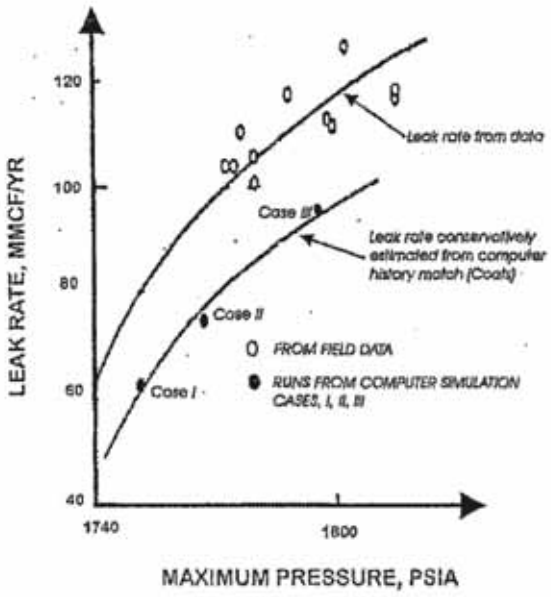


Fig. 5
Gas leak rate for various maximum reservoir pressures for Leroy Gas Storage project, Wyoming (modified after Tek 1987, Fig. 11–16)

Fig. 6
Los Angeles City oilfield (after California Division of Oil and Gas 1991)

the gas storage operator to maximize the storage volume, and to enhance retrievability of the gas when market demands dictate recovery (usually during cold spells when usage skyrockets). Also, cyclic operations associated with gas injection and withdrawal may create fractures.

Hutchinson, Kansas, gas storage leaks, explosions and fires of January 17–18, 2001

Underground gas storage leaks caused a devastating explosion and fires in the downtown area of Hutchinson, Kansas, on January 17, 2001 (Allison 2001). There was a release of natural gas from the ground water under several stores. Upon ignition, windows were blown out, and within minutes two businesses were ablaze. The fire department was unable to extinguish the flames because of the ongoing migration of gas into the area.

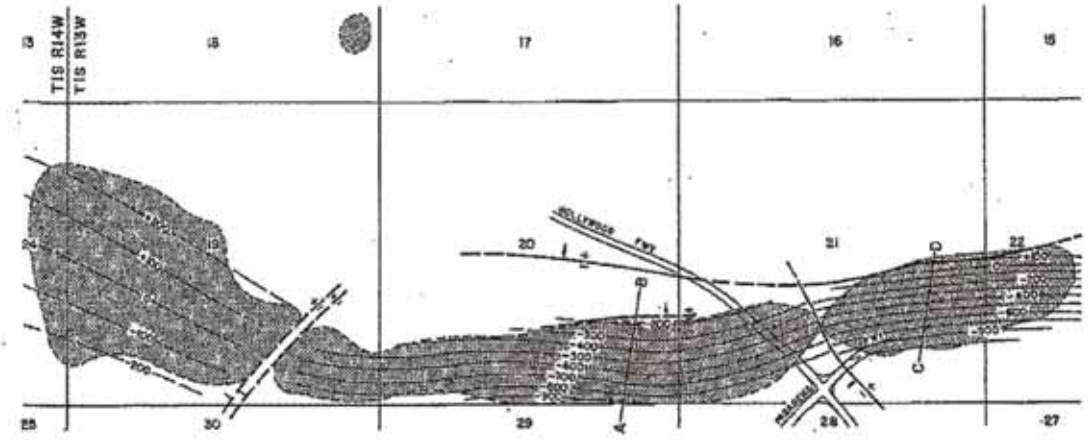
On the following day, leaking gas migrated into a trailer park on the outskirts of the town, causing a second explosion, and killing two people. The gas leakage was traced to a leaking storage gas reservoir about 7 miles from the town. Possibly, gas migrated along the fractures, formed as a result of subsidence, into the aquifer, and the water carried this gas to the sites of explosions.

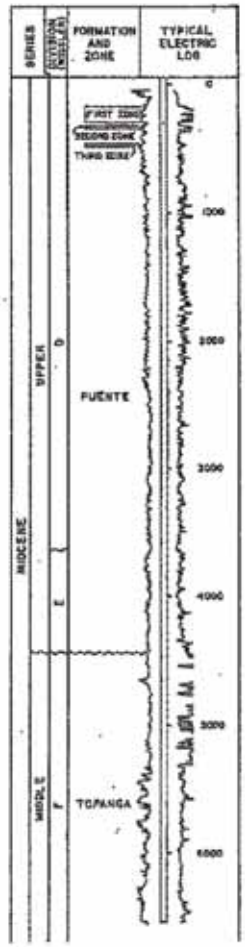
Santa Fe Springs oilfield

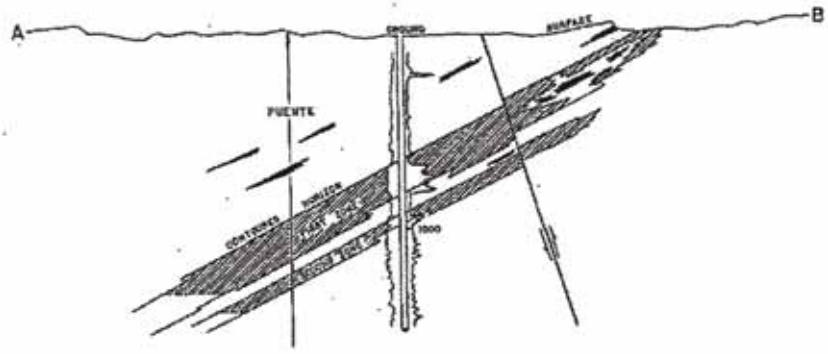
A study was undertaken by the authors to determine the integrity of operational oil wells in the Santa Fe Springs oilfield. To facilitate this review, a time period was selected after heavy rains in which the well cellars were partially filled with water. This allowed observation of gas bubbles seeping to the surface along well casings. Results were systematically recorded for more than 50 wells, some of which were used for waterflooding operations at pressures approaching 84.4 kg/cm^2. Approximately 75% of the wells were found to be leaking.

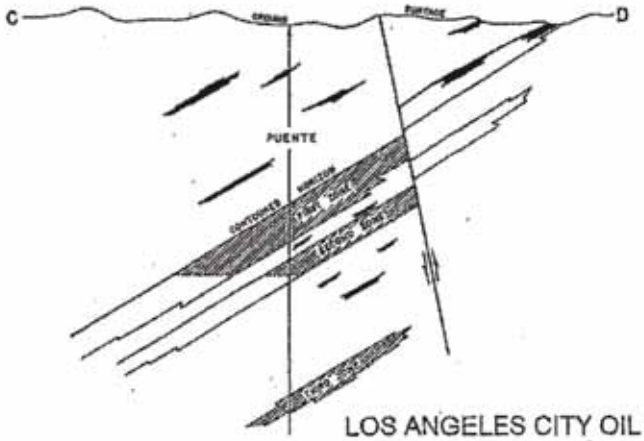
The waterflooding for enhanced oilfield recovery can be a dangerous practice due to hydraulic fracturing which could create avenues for the migration of gas to the surface creating an explosion hazard. Pressurization of an oilfield by way of water injection or gas injection requires careful attention to the integrity of the wells throughout the oilfield, and should not be undertaken until a soil gas monitoring program has been implemented in the vicinity of each well and fault to detect the potential leakage of gas to the surface. This is also necessary to determine the need for well repairs and/or well reabandonment.

D2-252 (Cont.)









LOS ANGELES CITY OIL FIELD

D2-252
(Cont.)

Belmont school construction on an oilfield

The Belmont Learning Center, a proposed high school in downtown Los Angeles, was in the process of being constructed over the Los Angeles City Oil Field before being abandoned. The site chosen was on a 0.14 km^2 parcel of land bounded by 1st Street to the south, Temple Street to the north, and Beaudry St. to the east. This location is over a shallow oilfield that has an outcrop to the surface just north of the building site. Furthermore, major faults criss-cross the area as illustrated in Fig. 6 (California Division of Oil and Gas 1991). The area is also part of the Elysian Park blind thrust fault system that has a generally east-west trend, which helps explain the uplifting and tilting of petroliferous formation depicted in Fig. 6.

Oil wells in the area continue to produce from shallow oil deposits at a depth no greater than 213 m. Most of the wells were drilled in the early 1900s, and continue to produce. All of the oilfield production gases are released to the atmosphere in the residential areas surrounding the wells. This includes four operational wells at the northwest corner of the school property.

Environmental studies, undertaken only after construction was undertaken, have revealed oilfield gas seepage to the surface over most of the 0.14 km^2 parcel, including the area directly under the school buildings. The project was abruptly halted when gas seepage was detected in the main electrical vault room of the project, just before the power was to be energized.

Soil gas studies revealed that methane (explosive levels) and other gases are migrating to the surface, including hydrogen sulfide. Measurements at the wellhead, and at other seep locations, revealed releases to the air of over 300 parts per million (ppm) of hydrogen sulfide. At depth, hydrogen sulfide was measured at over 3,000 ppm. These alarming results were extensively evaluated by the authors herein, and commented on during the many environmental reviews for the project (Endres 1999, 2002).

Over $175 million has been spent on the project by the Los Angeles Unified School District. At least $20 million has been spent on environmental site characterization alone.

A double passive membrane has been proposed to be installed over the entire 0.14 km^2 site. One expert proposed drilling of a slant well to intercept the main avenue of gas migration (fault) and, thus, divert the direction of gas movement.

A recent discovery of surface faulting extending under several of the school buildings has placed a further halt on construction, and may doom the entire project.

This case history clearly identifies the extreme caution needed in evaluating the environmental suitability of sites located over oilfields, especially for school construction. The State of California has passed recent legislation that requires direct participation by the Department of Toxic Substances Control (DTSC) in the future school site selection process in order to avoid a repeat of the Belmont failure.

Subsidence problems caused by oilfield fluids production

One of the most serious environmental problems caused by oilfield operations within the Los Angeles Basin has been subsidence (Chilingarian and others 1995). Subsidence exists in virtually every oilfield within the Los Angeles Basin (Wentworth and others 1969). Subsidence is caused by the reduction of pore pressure within the reservoir resulting from fluids production. The resulting increase in the effective stress causes compaction which is propagated to the surface, typically causing a bowl-shaped subsidence at the surface, centered over the oilfield (see Fig. 7). The subsidence area is approximately twice the size of the oilfield itself (Khilyuk and others 2000). The enormity of the problem is well known for the Wilmington Oilfield that reached approximately 8.5 m before corrective action was taken by implementing a massive water injection program. This required legislative action in order to bring about a unitization of the oilfield to allow the flooding water program to be implemented. It has also become the public policy of the State of California to arrest subsidence, especially in coastal areas, through the use of water injection.

Minimizing the consequences of subsidence requires implementing a subsidence-monitoring program. The standard in use today in oilfields throughout the world (Endres and others 1991) is the Global Positioning Satellite System (GPS). The disasters of the past can be directly traced to the failure to perform adequate monitoring for subsidence. Conventional surveying and now satellite geodesy, permit determination of vertical and horizontal movements of the land surface above oilfields with great accuracy and at relatively minimal cost.

The Baldwin Hills reservoir failure of 1963

On December 14, 1963, at about 11:15 a.m., an unprecedented flow of water was heard in the spillway pipe at Baldwin Hills Dam in the Inglewood Oilfield area of Los Angeles. A short time later water broke violently through the downstream face of the dam, causing massive property damage to homes located below the dam and five deaths. The owner, the Los Angeles Department of Water and Power, had operated the dam continuously from July 1951 until its failure on December 14, 1963. Although an ongoing surveillance for leaks within spillways was carried out, no monitoring for oilfield subsidence was undertaken. The Inglewood Oilfield, discovered in September 1924, lies under the western half of the Baldwin Hills area. It covers about 4.9 km^2 and in 1963 had more than 600 producing wells (see Fig. 8). The field adjoins the reservoir site on the south and west, the nearest reported production at the time of the reservoir failure being from three wells within 213 m of the south rim.

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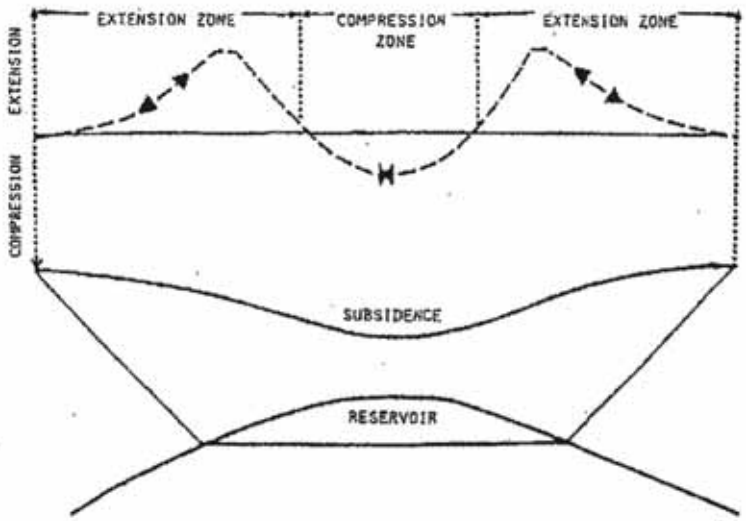


Fig. 7
Schematic diagram of compressive and tensile stress distribution in subsizing formation (modified after Gurevich and Chilingarian 1993, Fig. 1, p. 244)

Analysis of failure revealed ground movement that correlated directly with the Inglewood Oilfield fluids production (see Fig. 9). The total area of subsidence resembled an elliptical bowl with its center about 805 m west of the reservoir and centered over the oilfield. Subsidence at the reservoir site was about 0.9 m, compared to nearly 3.4 m at the subsidence bowl. Noteworthy was the fact that the southwest corner (viz., direction of maximum subsidence) had dropped more than the northeast corner, resulting in differential settlement across the dam of approximately 0.15 m. Furthermore, a review of survey data from 1934 to 1961 and 1963 showed lateral movement in the direction of subsidence depression.

The Inglewood-Newport Beach active strike-slip fault also bisects the area (see Fig. 8), with numerous faults branching off of the main fault in the area. Drilling records clearly reveal these many branching faults, indicating the enormous potential for differential movement along individual fault blocks. Indeed, a post-accident investigation revealed that differential fault block movement had caused rupturing of the asphaltic membrane used as a water seal over the floor of the dam.

Although fluid extraction and resultant subsidence were the prime contributors to the rupture of the reservoir, there is substantial evidence to indicate that water injection to stimulate oil production was also a contributing factor (Hamilton and Meehan 1971). Increased fluid pressures in the reservoir resulting from secondary recovery were sufficient to force brine water to the surface along faults. These forces, along with the lubricating influence of the water exacerbated differential movement along the individual fault blocks.

Recently, a large housing development was proposed for the Baldwin Hills area, virtually over the above described subsidence area. Large retaining walls (exceptionally high) were contemplated to enhance views (and presumably to add value to the individual lots). These retaining walls would have been extremely vulnerable to geologically active and subsidence-prone area. When the developer became aware of the history of land movement in the area from ongoing oilfield production, the property was sold to the State for use as a public park.

This case history highlights the importance of proper planning and monitoring of the land movement in an area that has been heavily impacted by major faulting, oilfield subsidence, and secondary recovery.

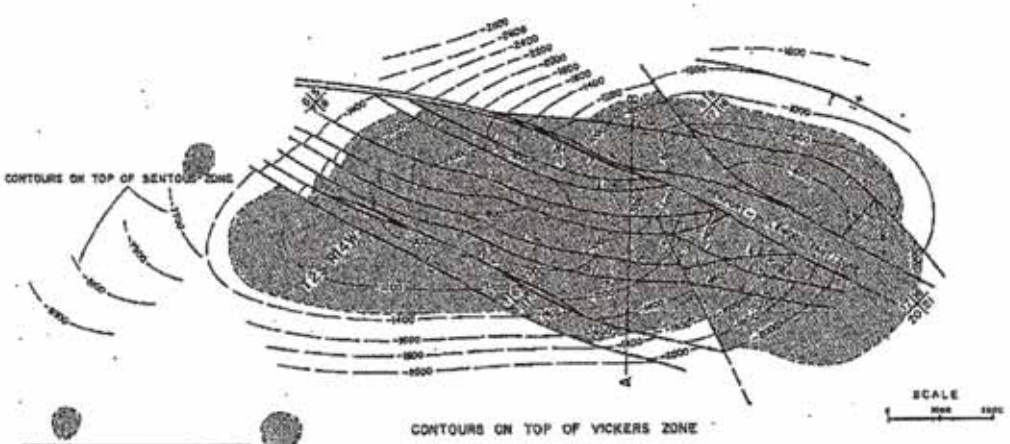
Redondo Beach, King Harbor subsidence

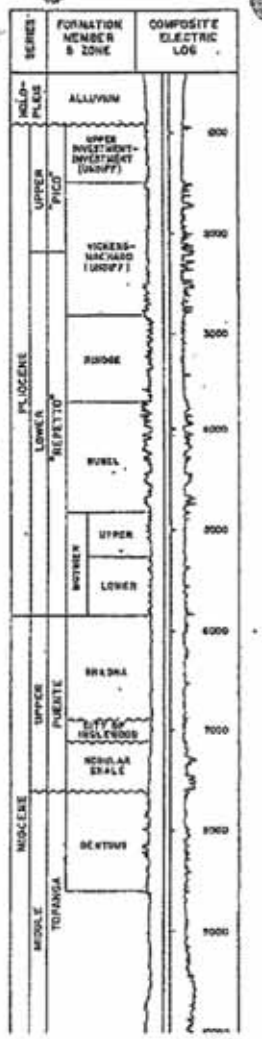
During a winter storm in January 1988, waves overtopped the breakwater constructed by the U.S. Army Corps of Engineers in order to protect the Redondo Beach King Harbor Boat Marina and surrounding commercial structures. Enormous damage resulted, including the destruction of the Portofino Inn. King Harbor is located at the northwest end of the Torrance Oil Field, directly over the Redondo Beach Oilfield (which is considered an extension of the Torrance Oilfield). The City of Redondo Beach had granted permission for offshore drilling from slant wells in that city.

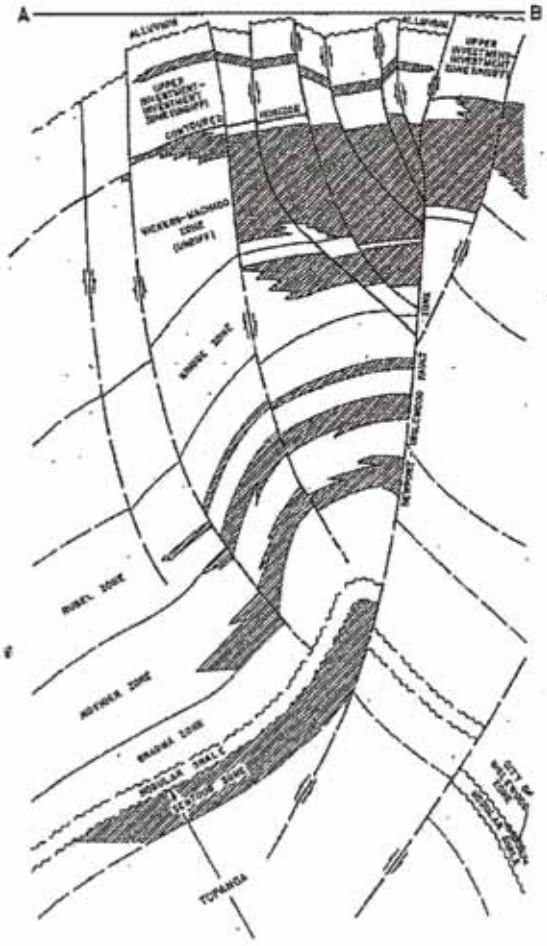
The heights of benchmarks (used by the U.S. Army Corps of Engineers to construct the breakwater) were based on a U.S. Coast and Geodetic Survey of 1945. These benchmarks were assumed fixed, because the Corps of Engineers did not suspect subsidence until 1985, when surveys showed the breakwater crests to be as much as 0.6 to 0.9 m above the original design elevations. Apparently, nothing was done to protect the harbor, or to warn the commercial establishments prior to the storm of January 1988.

Investigation following the disaster revealed that nearly 0.6 m of subsidence had occurred under the breakwater as a result of oil production beginning in 1943, but with

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INGLEWOOD OIL FIELD

D2-252 (Cont.)

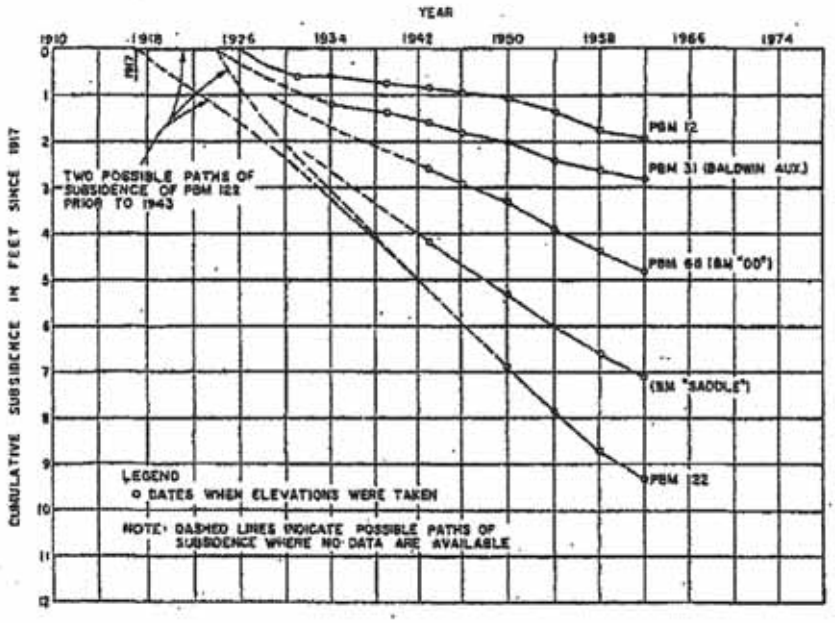


Fig. 9
Subsidence of benchmarks, Baldwin Hills area, Los Angeles, California (after California Department of Water Resources, Baldwin Hills Reservoir, Apr. 1964)

accelerated subsidence occurring after the approval of tideland oil production in 1956.

A jury trial in the Torrance Superior Court resulted in a multi-million dollar judgment against the U.S. Army Corps of Engineers and the City of Redondo Beach. Several oil companies involved in the oil production settled prior to the case going to trial.

The main lesson to be learned is that this disaster could have been averted if proper monitoring for subsidence had been undertaken. It is important to note that the judgment was upheld on appeal, in which the Appellate Court found that undertaking oilfield production in such an urban setting constituted an ultra hazardous activity, requiring the utmost standard of care. Virtually every oilfield in the Los Angeles Basin has experienced subsidence as a result of fluid production. Accordingly, an appropriate standard of care for all oilfield operators should be to undertake monitoring from the onset of production.

Playa Del Rey/Marina Del Rey subsidence

Historical measurement data regarding subsidence in the Playa del Rey/Venice oilfield areas reveal almost 0.6 m of subsidence from the time that oil production began in the 1920s and through 1970. However, no subsidence monitoring has occurred since 1970, despite the fact that fluid production has continued to the present. The Marina del Rey breakwater is vulnerable to subsidence, as is the coastal area.

The most vulnerable are the old wells that were drilled and completed in the 1930s. Any damage to the oil wells (including cements) due to movement along faults present the potential for increased gas migration to the surface. This is especially critical because the oilfields underlying the area are being used to store high-pressure gas transported in from out of the State of California. Figure 10 is presented to illustrate the interrelationship among earthquakes, gas migration, and subsidence resulting from oilfield production (Chilingarian and others 1995; Gurevich and others 1993).

Clearly, these oilfield operations required the utmost degree of vigilance in order to protect the high-density urban development in the area. Monitoring for subsidence and gas migration is essential in order to meet this standard of care.

The release of air toxics from surface operations, wellheads and pipelines

The Federal Environmental Protection Agency (EPA) has determined that the primary hazardous air pollutants (HAP) emitted from oil and natural gas transmission and storage facilities are (see Federal Register, Volume 63, No.25/Feb.6, 1998):

◀

Fig. 8
Structural contour map of the Inglewood Oilfield, Los Angeles, California. Contours are on top of the Vickers Zone (after California Division of Oil and Gas 1991)

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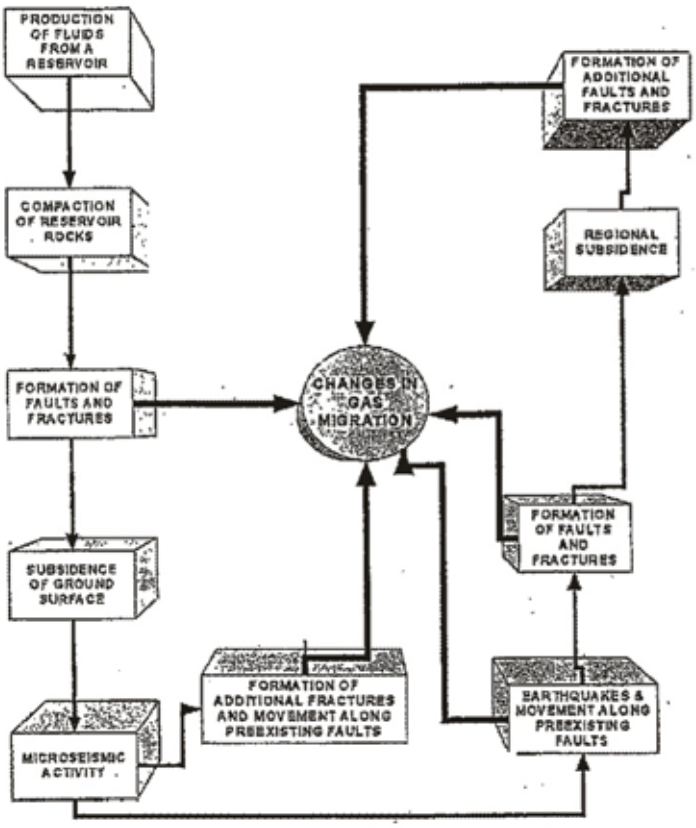


Fig. 10
Schematic diagram of system relationships among the production of fluids, compaction, subsidence, and seismic activity (Modified after Chillingarian and others 1995, Fig. 1, p. 41)

1. Benzene
2. Toluene
3. Ethylbenzene
4. Xylenes

These compounds are collectively referred to as the BTEX chemicals. The BTEX chemicals are the aromatic components of crude oil. For a further discussion of these hazardous components of crude oil see McMillen and others (2001). Although crude oil has variable contents of aromatic hydrocarbons, depending upon the origin, the API rating of the crude oil can be a good predictor of the content of aromatics, especially benzene (see Fig. 11). The higher the API gravity of the crude oil, the higher the percentage of aromatics in the crude oil.

Tissot and Welte (1978) found that 95% of the crude oils produced around the world fell into the distribution pattern shown in Fig. 12. As an example, the composition of a 35° API-gravity crude oil is as follows (Hunt 1979):

Molecular type	Weight percent
Paraffins	25
Naphthenes	50
Aromatics	17
Asphaltenes	8
Total	100

The majority of crude oils have been reported to contain 15 to 40% aromatics. The aromatics are characterized by a double carbon bond, which has been directly linked to the health hazards posed by these chemicals. Benzene, a known human carcinogen, has been linked in the medical literature to leukemia, aplastic anemia, lymphomas and a variety of other cancer related ailments.

Oil and gas production facilities are required to provide warnings to the public regarding certain hazardous oilfield chemicals, including benzene and toluene, under California Health and Safety Code Section 25249.6 (otherwise known as Proposition 65).

Most facilities are not required to identify the amount or the specific types of chemicals being released to the atmosphere from their operations. The Federal EPA has identified dehydration equipment as a major source of benzene and toluene air toxics emissions, and has proposed legislation to curtail such emissions, especially in residential areas.

Venting of oilfield gases to the atmosphere must be viewed as a hazardous activity, because the oilfield gases can contain appreciable levels of benzene. Oilfield gases and condensates have the highest contents of benzene. A typical content of benzene in the oilfield gases can vary between 30 parts per million (ppm) to over 800 ppm. For this reason, the natural gas should be carefully tested for its benzene content before venting of large quantities of

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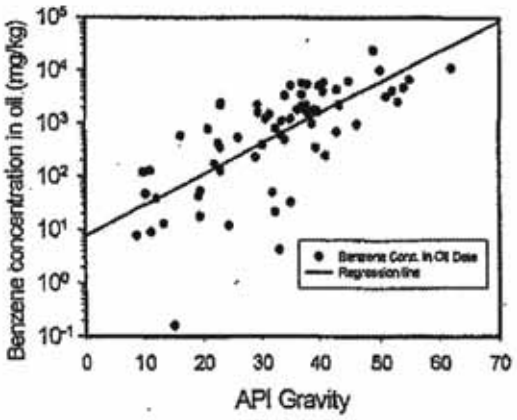


Fig. 11
Benzene concentrations versus API gravity for 61 crude oils and 14 condensates (API gravity data were unavailable for eight crude oils) (after Rixey 2001)

gas is undertaken. Also, vent stack emissions should be carefully monitored. Additional concerns and precautions must be taken in and around sour oilfield operations. Hydrogen sulfide, even in small quantities, can be hazardous to the health. The research conducted at the University of Southern California Medical Facility (Kilburn 1998, 1999) has established central nervous system damage from the neurotoxin effects of hydrogen sulfide even at concentration in air as low as 1 ppm. This is much lower than the workplace standards that have been considered safe in the past. This also highlights the importance of not relying upon workplace standards regarding air toxics emissions in the case of residential areas and school sites. Safety, health, and environmental considerations need to be made a top priority in the land use planning where urban development coexists with the oil- and gas-field operations.

Conclusions

The history of the Los Angeles Basin oilfields has demonstrated the need to exercise a high degree of vigilance regarding the environmental hazards posed by these operations. Land use planning and governmental entity decisions regarding allowing massive real estate development over and adjacent to these operations sometime ignored the health and safety risks posed by these operations. The primary purpose of this paper has been to show the importance of reviewing a long history of environmental problems created by this mixed land usage, and to identify what steps need to be taken to avert future disasters. This includes the necessity of taking the following steps:

Gas migration monitoring: Much closer attention must be given to the need to perform ongoing monitoring for gas migration into the near surface soils in areas heavily impacted by historical oil production, and where there are many old and abandoned wells. It is very important to monitor gas migration near the fault zones.

Subsidence monitoring: Monitoring for subsidence in the oil and gas producing areas is necessary in order to protect against the undermining of foundations and highly sensitive changes in elevation (especially in coastal areas), and to reduce the risk of gas migration hazards. Subsidence gives rise to faults and fractured zones, which are avenues for gas migration.

Air Toxics monitoring: The release of air toxics from surface operations, wellheads and pipelines must be carefully monitored in order to protect the public health, especially from the release of such chemicals as benzene, toluene, ethylbenzene, xylene (viz., the BTEX aromatic hydrocarbons) and hydrogen sulfide. Great caution is required in the operation of vapor recovery equipment and in the monitoring of toxic emissions in order to take corrective action.

Soil and groundwater monitoring: Soil and groundwater must be carefully evaluated for petroleum and drilling

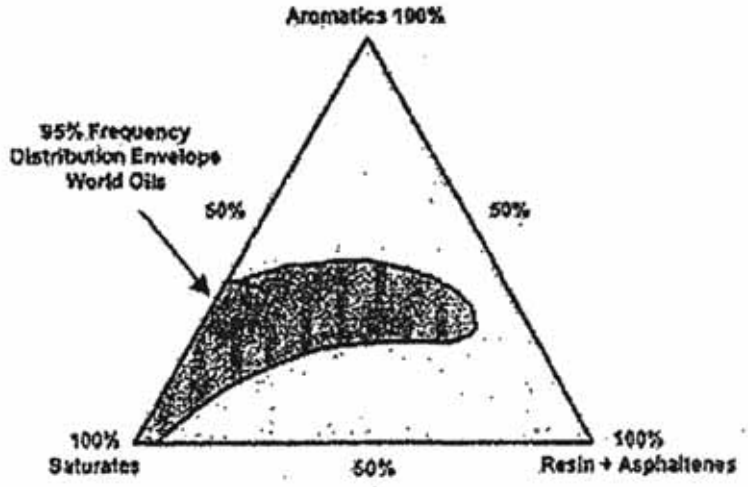


Fig. 12
Ternary diagram showing the class composition of crude oils (after Tissot and Welte 1978)

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(Cont.)

mud contamination, and appropriate steps must be taken to remediate the soil and water contamination before development is allowed to proceed. This requires an evaluation of the underlying aquifers, which become a ready target for the oil and gas migration hazards.

Soil gas monitoring: Soil gas monitoring is an essential step in the evaluation of soil and aquifer contamination by historic oil and gas field operations. It is also necessary to determine what mitigation measures may be necessary to protect against migration of explosive and toxic oilfield gases into residential and commercial structures. This will be an ongoing problem in many areas that must employ gas detectors, vent pipes, membrane barriers and ventilation systems in order to protect against the gas migration hazards.

Oil and gas well leaks and ongoing monitoring: Oil and gas wells must be carefully evaluated, and old wells must be reabandoned to protect against the risk of oilfield gases migrating up the old wellbores and entering the near-surface environment. There has been a long history of this very serious problem, establishing that the prior well abandonment procedures have been often inadequate in dealing with this extremely dangerous problem.

Building over abandoned wells: Land planning and issuance of building permits should require adequate room to provide access for a drilling rig to reenter old wells, when they begin leaking.

As a final conclusion, the authors would like to quote the editorial of Professor George V. Chilingar, Founder of Journal of Petroleum Science and Engineering and Managing Editor (J Petrol Sci Eng 9:237): "…. Underground gas storage and oil and gas production in urban areas can be conducted safely if proper procedures are followed." "After recognition of the existing problem, proper safe operating procedures can be easily developed."

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APPENDIX 8

HSE

Health and Safety Executive

An appraisal of underground gas storage technologies and incidents, for the development of risk assessment methodology

Prepared by the **British Geological Survey**
for the Health and Safety Executive 2008

RR605
Research Report

HSE

Health and Safety Executive

An appraisal of underground gas storage technologies and incidents, for the development of risk assessment methodology

D J Evans
British Geological Survey
Kingsley Dunham Centre
Keyworth
Nottingham
NG12 5GG

with contribution from:

Dr J M West (Microbiology)

This report was commissioned by the Health and Safety Executive to help assess the safety issues associated with the underground storage of natural gas. This has arisen because of the need to consider a number of applications submitted by various operators in the UK who wish to develop such facilities. The rising numbers of applications are as a result of UKCS oil and gas reserves showing rapid decline, to the extent that the UK became a net importer of gas during 2004. The Government recognises that the UK faces an increasing dependency on imports, yet has very little gas storage capacity and is, therefore, at a very real risk of supply shortfalls. It notes that the UK's capacity to import, transport and store gas and LNG efficiently has to be improved and this will require greater investment in new, timely and appropriately sited gas (and LNG) supply infrastructure, part of which is likely to include (safe) onshore underground (natural) gas storage (UGS) facilities.

This report and the work it describes were funded by the Health and Safety Executive (HSE). Its contents, including any opinions and/or conclusions expressed, are those of the authors alone and do not necessarily reflect HSE policy.

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First published 2008

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Foreword

This report is the product of a study by the British Geological Survey (BGS) into published or reported problems with and incidents at underground fuel storage facilities. It forms part of a risk assessment of underground gas storage in the UK for the Health and Safety Executive for which a contribution by Quintessa is presented in a separate report (Watson et al., 2007).

For ease of use, the BGS report is presented in two volumes. Volume One comprises the text and appendices. Volume Two contains the figures and tables referred to in Volume One.

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Disclaimer: this is wholly independent and impartial review and appraisal of the technology of Underground Fuel Storage (UFS), the incidents or problems encountered at various facilities and the general geological conditions of those areas, with an overview of the potential or likely areas for underground gas storage (UGS) in the UK, outlining the form that this might take. The BGS report neither promotes nor supports UFS, one particular form of UGS or any proposed facility location. Additionally, it does NOT address the control or prevention of pollution, safety of the surface or subsurface infrastructure: the assumption here being that the design, maintenance and operation of such facilities would be subject to the various HSE, waste and environmental regulations covered by such documents as the COSHH (2002), COMAH (1999) and appropriate British Standards. For specific elements of an underground gas storage facility, e.g. wells and surface installations, and operational procedures, it is assumed that UGS applications would be subject to existing BS standards and legislation for oil and gas exploration and should be applied or referred to in the first instance.

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The parallel legislation includes:

- The Health and Safety at Work etc. Act 1974
- The Borehole Sites and Operations Regulations 1995
- The Dangerous Substances and Explosive Atmospheres Regulations 2002
- The Control of Major Accident Hazards Regulations 1999
- The Construction (Design and Management) Regulations 1994 (as amended)
- The Pipelines Safety Regulations 1996
- The Pressure Systems Safety Regulations 2000

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Acknowledgements

Many individuals have provided discussion during the project and to whom the author is grateful. This assistance has been received at all stages of the study and their input or granting of permission to reproduce data/images in order to illustrate this report is acknowledged below. Dr Nigel Riley of the HSE is thanked for his detailed review of an early version of the draft report, comments on which greatly improved the final product. Ron Demaine is thanked for the final preparation of many of the diagrams contained in the report. The author would like to thank the following for support and advice during the work:

Drs N Riley and S Welsh of the Health and Safety Executive

Drs S Turner and D Keeley of the Health and Safety Laboratories

Mr E Hough, Drs GA Kirby, S Holloway, R Cuss, AH Cooper & NJ Riley and Professor M Culshaw (BGS)

Drs S Watson and R Metcalfe (Quintessa)

Jennifer Cunningham, BGS Wallingford (Figure 15 - major aquifers cropping out in England and Wales)

G Church and R Smith (BGS, IPR section)

Kate Sanderson (SABIC UK Petrochemicals) for information relating to the Teesside brine caverns and their usage

Richard Stevenson (INEOS) for information relating to operations in the Cheshire saltfield

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Summary

This report was commissioned by the Health and Saftey Executive, Bootle. It was requested as part of their operations to assess the safety issues associated with the underground storage of natural gas, for which an increasing number of applications to develop such facilities have been submitted by various operators in the UK. The rising numbers of applications are as a result of UKCS oil and gas reserves showing rapid decline, to the extent that the UK became a net importer of gas during 2004. The Government recognises that the UK faces an increasing dependency on imports, yet has very little gas storage capacity and is, therefore, at a very real risk of supply shortfalls. It notes that the UK's capacity to import, transport and store gas and LNG efficiently has to be improved and this will require greater investment in new, timely and appropriately sited gas (and LNG) supply infrastructure, part of which is likely to include (safe) onshore underground (natural) gas storage (UGS) facilities.

The main areas of interest and concern were, therefore, what type of facility might be developed in the UK and could the stored product escape? If so, what would any likely gas flux rates be and could the gas reach the surface, endangering populations? This report, therefore, attempts to summarise the main storage types available in the UK context, what, if any, incidents have occurred at similar facilities around the world and what were the consequences. A separate companion report by Quintessa (Watson et al., 2007) provides calculations of possible flux rates from a number of UK storage scenarios, drawn from the results of this study. The report is aimed at both non-specialists and specialist readerships and therefore contains brief introductory material to some of the geological and technical aspects of underground gas (or fuel; UFS) storage that will already be familiar to the more experienced reader. A series of appendices provide additional information for the reader interested in or requiring further detail in some areas. Given the wide-ranging scope of UFS/UGS, this report cannot and does not attempt to review all topics that might be involved, but where possible, the reader is guided to sources of further reading.

In the UK context, UGS is of two main potential types: salt cavern (man-made voids) and depleting oil/gasfields (pore storage). Opposition is raised by local groups to each UGS application who, quite naturally, fear the repetition of one or two high profile incidents that have involved small numbers of casualties both in overall total and at individual incidents. The opposition is raised and the same incidents quoted irrespective of storage type, which is important when assessing safety issues.

Over 90 years of expertise has now been gained in the technology of UGS, with around 630 UGS facilities (of different types) currently operational worldwide and there is perhaps a need to put the risks of UGS and UFS into perspective. This is in terms of both actual events and storage types, and relative to other areas of the energy supply chain. With this in mind, the BGS were asked by the Health & Safety Executive to provide an independent and impartial review of UFS and UGS incidents. The review is to assist them in assessing the geological safety and risks of gas leakage from underground storage facilities when dealing with UK applications to develop UGS sites.

This study has found 65 reports or accounts of problems encountered at UFS facilities from mainly America and Western Europe. Few cases have been found reported from Russia or Eastern Europe, but there is no reason to believe that there have not been incidents, it may be that they simply have not been reported or have been missed during this extensive search. Of varying severity and nature, those incidents found have been associated with 9 fatalities, around 62 injured and at least 6700 having been evacuated. The latter statistic does not include the

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numbers involved in the evacuation of the village of Knoblauch, 25 km west of Berlin, during the escape of town gas (and carbon monoxide) referred to above. Of the release incidents, 15 were accompanied by an explosion and/or fire, 10 having occurred at salt cavern facilities. Of the 9 fatalities found reported at 5 UFS incidents, 8 were at 4 incidents involving salt caverns in the USA that were not been limited to just natural gas, but included storage of other hydrocarbons. The ninth fatality occurred at an aquifer storage facility west of Berlin in the 1960s. The causes, scale, and severity of the 65 reported problems are described and shown to be extremely variable in magnitude and nature and dependent upon a combination of many factors. Most typically, release and accidents arise through failure of man-made infrastructure (including well casings and completions, pipes, valves and compressors), human error (utilisation of inappropriate and existing caverns, poor forward planning, poor management or operational practises and a lack of due diligence by the storage company or operator). One or two problems have resulted from (extreme) natural events (e.g. seismic activity) that would not be relevant to the UK.

The report also contains reviews of some incidents or developments at oil and gas fields and operational salt mines (both conventional 'dry mining' and brine extraction) that could have some bearing or importance to the assessment of risk/hazard in gas storage operations. They illustrate actual events during operations and that could happen during the development or operation of gas storage facilities if poor practices are employed or stringent monitoring of processes is not performed.

Casualty figures from other areas of the energy supply chain, including above ground storage vessels are reviewed. This allows those figures associated with UGS/UFS to be compared with other storage environments and parts of the energy supply chain to assess the conclusions of Bérest et al. (2001) and Bérest & Brouard (2003). These authors state "salt caverns provide one of the safest answers to the problem of storing large amounts of hydrocarbons". Pore storage facilities are associated with even lower incident and casualty rates. Even in urban areas such as Los Angeles, Chillingar & Endres (2005) concluded "...Underground gas storage, oil and gas production can be conducted safely if proper procedures are followed. After recognition of the existing problem, proper safe operating procedures can be easily developed"...

Whilst it is acknowleged that the figures reported here probably represent a minimum (i.e. it is unlikely that all incidents have been found, or were reported), the figures collated during this work indicate that UGS has extremely low incident and casualty numbers. Rates several orders of magnitude greater are reported from other sections of the energy supply chain and which individually, have often resulted in more deaths than those of not just UGS, but all combined UFS incidents described here. This includes fatalities arising from the supply of domestic gas in the UK.

Contrary to public belief, UGS is regarded by other sectors of industry and research as having an excellent health, safety and environmental record (Lippman & Benson, 2003; Imbus & Christopher, 2005).

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1 Introduction

There are a growing number of applications to develop underground gas storage (UGS) facilities in the UK (refer Fig. 1 & Table 1), each of which has been accompanied by significant opposition from local communities opposed to the development, mainly for perceived safety reasons. In the light of these applications and the opposition raised, there is a need to assess the safety record of previous and existing underground fuel storage (UFS) facilities and not just natural gas storage. This report was commissioned by the Health and Safety Executive (HSE), which is the regulatory organization that will be required to advise and inspect safe operational and working practices for such developments should they be granted planning permission and ultimately proceed to operational status. The aim of the study has been to identify and describe the main types of underground storage facilities used, any documented or reported failures and incidents leading to release of stored product, the types and number of casualties that resulted from the incident and what measures were required to bring any incident under control. The results of the research into the problems and failures of UFS sites will form a major part of a risk analysis and assessment of UGS in the UK context. This part of the study was undertaken by Quintessa and the Health and Safety Laboratory (HSL), with Quintessa providing calculations for potential release scenarios from possible UK UGS facilities (Watson et al., 2007). Quintessa have considerable experience in such work related to the underground disposal/storage of nuclear waste and CO_2.

This work will, by the nature of the industry and technological progress, be a work in progress, providing a present day 'snapshot' of the situation and our understanding. Continued monitoring of the literature and the progress of UGS applications will almost certainly provide additional material that can feed into the results of this study and support future work.

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1.1 BACKGROUND

Until recently, abundant North Sea gas reserves have meant that swings in UK demand have been taken up by increasing, or decreasing, output from North Sea gasfields. However, these fields are rapidly depleting to the extent that the UK became a net importer of gas during 2004 and UK North Sea fields no longer provide this flexibility (Fig. 2). With UK gas consumption both for domestic use and for electricity generation predicted to continue rising, the UK will become increasingly reliant upon imports (DTI, 2006a&b). The Government, clearly mindful of the UK's impending move towards increasing import dependence on gas and increasing shortfall in supply, recognises that the UK economy and gas users face major challenges in the face of continued growth in demand (DTI, 2005, 2006a&b). Any weakness in infrastructure could result in higher gas prices, or interruptions to supply, with damaging consequences for both UK markets and consumers. To meet these challenges, manage the changes and lessen impacts on UK users, the Government believes that there will be a need to substantially increase the UK's capacity to import, transport and, most importantly, store gas (and LNG) efficiently (DTI, 2006a&b; 2007). The UK will require greater investment in new, timely and appropriately sited gas import and storage infrastructure to provide a balanced portfolio of gas storage facilities meeting market requirements. These will include short-term (peak shaving) units such as above ground tanks that can be filled, emptied and refilled on an hourly or daily basis. However, larger and longer-term gas storage capacity may be best met through construction of underground gas storage (UGS) facilities in salt caverns, which whilst offering hourly or daily withdrawals, best provide weekly to monthly storage cycles, or pore storage facilities (depleted oil/gasfield reservoirs or aquifers), which provide more strategic and longer-term seasonal swing capacity.

Development of (longer-term, seasonal) aquifer storage in the UK is, for many reasons, thought likely to be some way off and is not considered a priority at this stage of this report.

UK onshore geology would permit a significant volume of natural gas to be stored underground in a variety of subsurface facilities, providing a blend of longer and shorter-term storage to meet the differing supply demands. At present, UK UGS applications are subject to numerous planning consent processes, both local planning controls, currently overseen by the Department for Communities and Local Government, and specialist development consent regimes currently administered by the Department for Business, Enterprise and Regulatory Reform (DBERR) and prior to June 2007, known as the Department for Trade & Industry (DTI). As the majority of this report was undertaken whilst it was the DTI, this report will refer to the DTI, but the reader is advised of the government department name change. In addition, local communities close to proposed facilities are fearful of a repetition of major incidents seen at certain UFS facilities, most notably in the USA. Consequently, almost every UGS application in the UK is opposed on safety grounds, often quoting inappropriate examples of facility failures to those applications placed. This brings further confusion to the assessment of applications and delays to the process of approving and consenting (or not) of any developments.

In terms of the safety of both UFS and UGS facilities, it requires knowledge of the past history of UFS and any incidents that have occurred at such facilities. The first storage of gas in an underground facility took place in a gasfield in Welland County, Ontario (Canada) in 1915. The first gas storage facility in a depleted reservoir was built in 1916, using a gasfield in Zoar near Buffalo, New York (USA). The latter is still operational (WGC, 2006) and there is, therefore, over 90 years of expertise now gained in UGS technologies. Worldwide, there are currently around 630 UFS facilities operational (Table 2), comprising three main facility types: depleted oil/gasfields, salt caverns and aquifers. The total volumes of gas currently stored in such underground facilities are around 320 billion cubic metres (Bcm[1]), providing daily deliverabilities of around 5.1 Bcm (Table 2). Over the period of 90 years, some 65 accounts of problems or incidents of varying cause, severity and nature at UFS facilities have been reported. A small number of these incidents (5) have led to 9 fatalities, with overall, around 62 injured and circa 6700 having been evacuated during these and other UFS incidents.

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1.2 RISK ANALYSIS AND RISK ASSESSMENT OF UGS

The hazards and risks associated with gas storage in geological formations are a recurring topic whenever UGS is discussed. Hazard is taken to be the likelihood of leakage taking place. Risk is the likelihood of actual damage or loss resulting from leakage. The hazards and risks associated with storage of natural gas relate to many areas, such as system integrity, health, safety and environmental effects, economic risks and risks related to public perception and trust. Risk analysis is a tool for quantifying risk and is (normally) based upon the product of frequency and consequences of a hazard. This report focuses on identifying and defining the health and safety related risks, although not unexpectedly, some environmental risks are covered.

The major hazards associated with the operation of an underground natural gas storage facility relate to leakage of the product from the storage structure into adjacent and overlying formations and thence to the surface, which carries two very contrasting risks (Lippmann & Benson, 2003):

(1) The stored product may escape, reaching ground surface whereupon it could then represent a significant health and environmental risk.

(2) Economic burden/risk – the stored product migrates away from the storage area, whereupon it is not recoverable and a valuable commodity is lost.

[1] Bcm = 10^9 m^3, or 1000 million cubic metres (Mcm = 10^6 m^3). Mcm is as used by the DTI.

Although economic risk is important, this report focuses on the risks health and environmental risks. It is noted, however, that various processes and consequences will be common to both risk types. For underground fuel storage the risks can initially be broken down into three phases:

- During construction of the facility
- During operation of the facility
- Following closure and abandonment of the facility

To determine and calculate risk, potential sources of harm must be identified and the probability and consequence of them occurring must be estimated (risk analysis). There is then a process of comparing the estimated risks against risk criteria to determine the significance of risk (risk evaluation). The process requires assembling a number of discrete sets that include information on (Vendrig et al., 2003):

- Identification of hazards
- Frequency of occurrence of hazards
- Consequence of hazard occurring

Risk analysis of geological storage of natural gas is complicated, to some extent, by the fact that in some cases no data or only limited data for frequencies or consequences are available. There are two main areas: the engineered system, which includes the infrastructure bringing the gas to the storage facility (the above ground components) and the geological system in which the gas will be stored, which will include the man made/engineered infrastructure (boreholes, cements, valves, pipes etc.). Accidents or hazards of the engineered system include failures caused by mechanisms such as corrosion, vibration, external impact and are expected to apply to such components as pipelines (buried and surface), flanges, valves, fittings, pressure vessels, pumps, compressors and injectors, wells and their casings/cements.

As mentioned above, it is the geological system that will be the focus of this initial risk assessment for the HSE and is expected that potential operators will have to provide assessment of the reservoir rock, caprock, nature of a salt body, geological features – thin non-halite interbeds, faults etc. Clearly, however, the engineered system plays a major role in the development of any UGS facility and components are so intricately linked with the geological system (e.g. wells, casing, cement, valves, flanges, pipes etc) that they necessarily appear in the risk assessment here. The range of possible release scenarios for a given component may cover a wide range of events from a pinhole leak to catastrophic pipe rupture or a failure of the storage environment (e.g. salt cavern). Such events might be due to wear and tear, subsidence, communication with other caverns or inadvertent intrusion through boreholes due to poor planning and site characterization. This will also include excavation activities. The risks and control of these components should, however, be more fully covered by the various COMAH and HSE legislation (Vendrig et al., 2003) and which have been successfully applied to oil and gas exploration in the North Sea (and onshore) for over 40 years.

In summary, UGS facilities are designed and operated to avoid leakage. The operational pressure ranges of UGS facilities are designed to be lower than those that would induce hydraulic fracturing (opening up of fractures) in the rock. To avoid leakage through the cap rock the applied overpressures must also, therefore, be lower than the displacement/entry pressures, which are generally less than the fracturing pressures.

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1.3 STRUCTURE OF THE REPORT

The report is structured in such a way as to lead the reader through the concepts of the UGS and build up the background data required to then make the risk analysis/assessment for UGS. The main text aims to present the basics and provide an introduction the main subjects. Appendices

1-8 provide further detail in certain areas for the non-specialist reader or those interested in additional detail.

The report opens (Chapter 2) with a general overview of the basic concepts, various types of facility, processes and numbers of Underground Fuel Storage (UFS) facilities in operation and the hydrocarbon products generally stored. Some basic descriptions of terminology such as 'working' and 'cushion' gas are included. In addition to reviews of the three main storage types that might be developed in the UK (pore storage [depleted oil/gasfields and aquifers] and salt cavern), are brief introductions to other forms of underground energy storage including hydrogen and compressed air that might in the future use the same rock formations and be the subject of planning applications in the UK.

Chapter 3 provides a review of natural hydrocarbon (oil and gas) seeps in sedimentary basins and some calculated and measured gas flux rates. It also outlines the fact that there are over 170 documented oil and gas seepages in the onshore UK area, many of which are active today and drove the early UK onshore oil and gas exploration. Appendix 1 provides examples of measurements of natural gas leakage rates and fluxes.

Chapter 4 outlines salt deposits and the factors relevant to developing gas storage caverns. Included are sections on salt properties, rheology and its self sealing nature due to viscoplastic deformation mechanisms, the development of wet rockhead and subsidence associated with salt beds, interbeds, fractures and infilling materials, the problems encountered in salt mines and areas of salt with old wells, all of which have some relevance to gas storage developments. More detailed descriptions of some events are given in Appendix 2.

Following the outlines of storage types and salt deposits, Chapter 5 provides an overview of underground gas storage (UGS) in Britain, outlining the areas in which development in the short to medium term is most likely for depleting oil/gasfields and salt cavern storage. Other forms of storage (aquifer, lined or unlined caverns, abandoned mines etc) may become favoured or technically and/or financially possible, but are not covered in this report. More detailed descriptions of UK operational or proposed developments are given in Appendix 3.

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Chapter 6 deals briefly with faulting and UK seismicity. Basic principles of faults and fault rocks developed are covered, including sealing or non-sealing capacities of faults and fault zones. There is then a review of UK seismicity and the risks and types of hazard that might be predicted, expected or impact on UK underground gas storage scenarios. The UK is seen as not at risk of surface rupture, but has low to moderate seismicity that is sufficiently high enough to pose a potential hazard to sensitive structures such as dams, chemical plants and nuclear facilities. It concludes that in terms of UK proposals, potential sites lie in regions affected by earthquakes and that each application should be dealt with on site by site basis. Appendix 4 provides earthquake intensity and magnitude scales.

Chapter 7 assesses the effects of methane storage on microbial populations in reservoir rocks and whether gas storage would lead to adverse effects on the reservoir rock, boreholes (e.g. well cements and metal pipes) etc.

Chapter 8 deals with some of the preliminary issues relating to gas injection and the cyclic nature of gas storage operations, such as subsidence and microseismic activity and what impacts these have had in other areas in which gas storage is ongoing. This is mainly relating to oil and gasfields, although many of the principles are the same for caprocks in salt cavern storage.

Chapter 9 forms one of the main areas of this research and is aimed at assisting the HSE to assess safety cases for UGS. It summarises those reports found through literature and internet-based searches on incidents and casualties at UFS sites, including UGS facilities. More detailed descriptions of the incidents found are provided in Appendix 5. It deals with the incidents by storage type, i.e. depleted oil/gasfields, salt cavern, abandoned mine etc. Outlines of some gas leaks at producing oil and gasfields are also included, particularly in the California area, which

geologically represents a very different environment to the UK, but has attracted interest in terms of safety records.

Chapter 10 outlines the incidents and casualty rates from the oil and gas production/supply chain and petrochemical industries and contained in two or three major reports. This includes the casualty rates involved in the supply of domestic gas in the UK and USA, and is aimed at providing some means of assessing the incident and casualty levels in UFS described in Chapter 9.

From the preceding chapters and descriptions of incidents, Chapter 11 summarises the main risks and release scenarios when considering UFS and UGS and provides a framework and list of parameters for risk analysis and assessment. The background information and considerations are contained in Appendix 6. The chapter discusses the risks in UGS in general and what might be seen as the additional main issues relating to gas storage in salt caverns. The risk assessment parameters for consideration in risk analysis/assessment of UK scenarios are then developed and summarised, with Appendix 7 containing detailed parameters for the various identified UK scenarios. These findings were then input into a sister study undertaken by Quintessa defining the Features, Events and Processes (FEPs) relative to UGS and which has undertaken scoping calculations for gas release from potential UK UGS scenarios (Watson et al., 2007).

Chapter 12 draws together the various findings of this report to produce a summary of the main risks associated with UGS and considerations in the UK context of UGS.

To keep the main report as short as possible, much of the supporting information and detailed descriptions of, for example, the various problems and incidents at existing salt mines or brinefields and reported during UFS operations, are included in Appendices 1 to 7. Should the reader require further information on certain aspects then they are referred to these more detailed summaries at the back of the report.

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2 The various types and numbers of Underground Fuel Storage facilities and stored products

The following briefly outlines the products and options most likely to be considered for underground (geological) natural gas storage facilities. Other options are available. These include abandoned/reconditioned mines and lined rock cavities. However, these are considered unlikely in the UK context for the foreseeable future, as many represent marginal, high cost and low volume scenarios.

2.1 HYDROCARBON PRODUCTS

Currently, the main hydrocarbon products held in underground (geological) storage are:

- Crude oil
- Natural gas
- Liquefied petroleum gas – (also called liquid petroleum gas, LPG, LP Gas) is a mixture of hydrocarbon gases, which is a gas at atmospheric pressure and normal ambient temperatures, but can be liquefied when moderate pressure is applied, or when the temperature is sufficiently reduced.

A further option to use underground storage in the transporting and storage of liquefied natural gas (LNG) is being evaluated (the 'Bishop Process' - section 2.2.9). This will involve importing LNG via tanker, converting (regassification) it to gas and then offloading for storage in underground facilities, which will be the same as for the above 'conventional' forms.

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2.2 THE BASIC CONCEPTS AND STORAGE SCENARIOS

Underground storage has and will increasingly play an important role in the natural gas supply industry. Gas in pipelines provides part of the UK storage capability. However, this volume is limited. Additionally, gas typically flows through the network of distribution pipelines at around 25 mph. So gas imported at one import terminal requires time to get from 'a' to 'b'. UGS provides a number of advantages that include the capability to store gas more locally and thus withdraw and supply to industry/users more quickly. UGS also ensures supply reliability during periods of heavy demand by supplementing pipeline capacity, serving as backup supply in case of an interruption in wellhead or gasfield production. Storage also allows load balancing of daily throughput levels on pipelines, which may be necessary to ensure smooth operation of the pipeline system. A relatively recent development in the use of storage is to manage inventory levels to take advantage of expected price movements and to support futures market trading.

Three main storage facility types that exist are:

- Depleted oil/gasfields
- Aquifers
- Salt caverns

Other facilities have been developed in abandoned mines, both coal mines and salt mines, and in lined rock caverns (LRC's) as investigated in Sweden and in the USA near Atlanta, Georgia and Boston, Massachusetts (EIA, 1995). Although more expensive than conventional means of storing gas (in depleted oil or gas fields, aquifers or salt formations), LRC's allow gas to be withdrawn and injected multiple times during the year which isn't always possible with the other methods. These alternative facility types are, however, rarer or only in concept stage and in the

case of abandoned mines, have proved problematical with leakage of stored product through cap rock sequences.

As alluded to above, worldwide there are around 630 UGS facilities currently operational (Table 2). The US operates the highest number, with 394 (although 37 were classified as marginal at the end of 2005 – that is no injections or withdrawals, or withdrawals only were made; EIA, 2006). This figure compares with 410 underground natural gas storage facilities in operation in 1998 and a peak figure of 418 operational sites in 2001. Between 1998 and 2005, 42 facilities were abandoned as uneconomic or defective, while 26 new sites were placed in operation (EIA, 2006). Europe has around 120 facilities currently operational.

The vast majority of UGS facilities are developed in depleted (or depleting) oil/gasfields (478 or 76%), with those in aquifers (80 or 13%) outnumbering those in salt caverns (66 or 11%). Other facilities (abandoned mines or lined rocks caverns) represent negligible percentages.

Most depleted reservoir storage facilities are designed to be cycled only once each year and typically require between 70 and 200 days to refill (EIA, 1995; Plaat, in press). In contrast, salt cavern facilities are designed with the intent of cycling the entire working gas capacity perhaps 5 to 10 times each year. Typical injection periods are in the range of 20 days.

The factors that determine whether or not a depleted reservoir or salt cavern storage facility will make a suitable storage facility are both geographical and geological. Geographically, potential sites would, ideally, be relatively close to the consuming regions or industry. They must also be close to transport infrastructure, including main and trunk pipelines and distribution systems. Geologically, pore storage options (depleted oil and gasfields and aquifers) require good porosity and permeability. The porosity of the formation determines the amount of natural gas that it may hold. The permeability determines the rate at which natural gas flows through the rock formation, which in turn determines the rate of injection and withdrawal of working gas. Together, the porosity and permeability of reservoirs determine the effectiveness or performance and thus economic viability of any specific site. Depleted hydrocarbon reservoirs, because they have held and produced hydrocarbons, tend to have high permeability and porosity. They have also proved the integrity of the trap to retain hydrocarbons over geological time (millions of years). This is different for aquifer storage, where the porosity, permeability and cap rock all have to be proven, which is more expensive and impacts upon the viability of any proposed development.

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2.2.1 Basic concepts, 'working' and 'cushion' gases

More detailed and specific characteristics of depleted reservoirs, aquifers, and salt caverns are outlined below (and can be obtained at http://www.naturalgas.org/naturalgas/storage.asp), but essentially, an underground storage facility is prepared ("reconditioned") prior to injection, to effectively create an underground, pressurised storage container. In the case of depleted oil/gasfields or aquifers, natural gas is injected into the interconnected pore spaces that exist between the constituent grains that make up the formation (and which have not been infilled by microbes or cementing minerals such as clays and quartz – section 2.2.4), whilst in salt caverns it is injected into the void created in the salt, building up pressure as more natural gas is added. As in the case of newly drilled oil or gas wells, the higher the pressure in the storage facility, the more readily gas may be extracted. Once the pressure drops to below that of the wellhead, no pressure differential exists to 'push' the natural gas out of the storage facility.

Two types of gas are referred to in storage terms:

- Working gas (sometimes called the working volume), is the maximum volume of gas available for withdrawal during the normal operation of the storage facility. Obviously, this is greatest when the facility has been filled to capacity. The capacity of storage facilities normally refers to their working gas capacity.

- Cushion gas (sometimes called base gas), represents gas that is present permanently in the UGS. This gas is not available for withdrawal and is required to maintain adequate pressure and ensure that sufficient energy is available to provide the required deliverability. In a salt cavern facility the volume of cushion gas may represent that gas required to maintain a minimum pressure to prevent the inward closure of the cavern walls by natural salt creep. In aquifer and cavern storages all the cushion gas needs to be injected. In depleted gas fields part, or all of the cushion gas, is gas that was originally in place.

The sum of cushion and working gas is often called the inventory and the capacity of storage facilities normally refers to their working gas capacity. As the working gas is injected against the cushion gas, pressure in the reservoir increases. Care must be taken not to overpressurize the gas reservoir due to the potential for leakage and for compromising the integrity of the formation caprock (often shale). At the beginning of a withdrawal cycle, the pressure inside the storage facility is at its highest; meaning working gas can be withdrawn at a high rate. However, as gas is withdrawn, the volume of gas stored decreases, pressure drops and the performance and deliverability of the storage facility decreases. A point is reached when it is no longer economically feasible to produce gas. This is dependant upon the physical properties of each storage site. Periodically, underground storage facility operators may reclassify portions of working gas as base gas after evaluating the operation of their facilities, particularly in the case of aquifer storage facilities.

In the normal operation of the storage facility, cushion gas remains underground. In the case of pore storage it would ultimately be left underground, although specialized compression equipment at the wellhead may permit a portion of it to be recovered. In salt caverns, unlike in pore storage facilities, most gas can ultimately be recovered prior to closure of the facility. This is because on abandonment, caverns are often filled with brine, which provides the cavern wall support and displaces the last remaining gas.

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2.2.1.1 Composition of cushion gases and 'blanket' materials

As indicated by the name "cushion," compressibility is the key property of cushion gases. Because all gases are compressible, just about any gas can be used as a cushion gas. However, the efficiency of gas storage operations can be increased if the cushion gas has greater effective compressibility. In order to maintain pressure in depleted reservoirs, about 50% of the natural gas in the formation must be kept as cushion gas.

As the methane from a depleting gas reservoir can be sold for profit, the operator's aims are to produce most of the gas and therefore, injection of a cheaper inert gas for use as the cushion gas is often considered. Whilst this also generates additional gas and thus revenue in the case of depleted gas reservoirs, in the case of aquifer or salt cavern storage, it also means that the operator does not have to buy and use expensive methane as a cushion gas. Although the use of inert cushion gases in the USA has been considered (e.g., Walker & Huff, 1964; U.S. DOE, 1980), they are not widely used (Oldenburg, 2002). However, inert gases such as nitrogen (N_2) have been successfully injected specifically for use as cushion gas in Europe (e.g. Laille et al., 1986; 1988; Misra et al., 1988). Nitrogen, in addition to being used during cavern construction to protect the already created void from the effects of brine during continued solution mining of the remaining volume, is also used as cushion gas in salt cavern storage facilities, being injected and withdrawn as required during cavern filling or emptying cycles.

The physical properties of carbon dioxide (CO_2) make it a potential choice as a cushion gas in pore storage scenarios. This is related to its high effective compressibility near its critical pressure when it undergoes a large change in density (Oldenburg, 2002). Injection of CO_2 has, for many years, been undertaken in a number of oil fields and is used to enhance oil and/or gas recovery. At the same time use of CO_2 would have the added bonus that whilst filling the

reservoir with CO_2, it would also provide a method of carbon sequestration (e.g. Oldenburg, 2002).

Whilst CO_2 injection has been employed in many instances to improve production of oilfields, studies on the site specific CO_2-rock interactions might be required to assess the likely impact of the CO_2 on both reservoir and caprock sequences. CO_2 could, for example, cause drying out of caprock shales, thereby altering the physical properties and strength, potentially leading to cracks and leakage pathways for gas.

In some salt caverns, a diesel blanket is used to provide protection against further leaching of the already constructed cavern roof and sides. However, it can also be used as an injected material when the cavities are operated in 'compensated mode' like that of brine compensated withdrawal and injection. It represents a more expensive option to brine, but would not carry the potential dangers of further salt solution and enlargement of the cavern (should the solution rate be faster than the salt creep processes).

2.2.2 Permeabilities and capillary entry pressures of well cement, shale and salt

As would be expected, a vast literature exists on the various well cements developed in the oil and gas exlporation, geothermal and waste well sectors and this cannot be reviewed here. However, an excellent entry to well cementing is provided by Nelson (1990). It is to be reasonably expected that any prospective operators of gas storage facilities will have designed the construction and completions of wells to the standards used in the oil and gas sectors: experience in these industries having been acquired over more than 100 years.

Those wells penetrating salt-prone sequences or aiming to develop salt caverns should meet the requirements of the drilling fluids not to dissolve the host salt and to obtain gas-tight well completions (bond between well cement and the borehole walls and well casing). On the latter point one study on the bond strength between the cement plug and host rock in abandoned boreholes is worthy of note (Akgün, 1997). Under testing, dissolution along the interface of the cement and the salt was observed, reducing bond strength. This might have been enhanced by clay inclusions in the salt. Gaining detailed information on the purity of halites beds might, therefore, be an area of extra consideration when assessing bedded salt successions in the UK.

Studies of potential for leakage of cement bondings in wells for CO_2 injection and storage have shown that degraded segments of well cements might have permeabilities of 10^{-1} mD [10^{-16} m^2] (Celia et al., 2006). To produce significant leakage (1% fraction CO_2), the effective permeability associated with the well must increase to about 10^5 mD (101 Darcy [10^{-10} m^2]), which is many orders of magnitude larger than the permeability of intact cement (10^{-5} mD [10^{-20} m^2]; Nelson, 1990; Celia et al., 2006). This illustrates clearly that in this case, well-formed cement will not leak any CO_2 (Scherer et al., 2005). Based upon these data, less than well-formed cement behind well casings is more permeable than any evaporite bed that an oil or gas injection well intersects

Important to the concept of gas storage are the permeabilities and capillary entry pressures of the caprock or containing rock type. Capillary pressure in rocks is the pressure at which the nonwetting phase first displaces the wetting phase and is controlled by interfacial tension between grains, 'wettability', and the pore throat size distribution (section 3.4). The seal capacity is the maximum hydrocarbon column height that a seal can trap, which is controlled by the capillary entry pressure.

Salts may be both a storage medium (caverns) and provide seals to economic accumulations of hydrocarbons. Gas hydrates (clathrates) aside, salts (and associated evaporites) provide the most effective seal to hydrocarbon traps, regardless of hydrocarbon type and structural setting (Downey, 1984; Warren, 2006). Evaporite seals have very high entry pressures, very low permeabilities and large lateral extents and maintain seal integrity over wide areas and a range of

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subsurface temperature and pressure ranges. Typical shale seal permeabilities are 10^{-1} to 10^{-5} millidarcies (mD)[2] [10^{-16} m^2 to 10^{-20} m^2] and rarely as low as 10^{-8} mD [10^{-23} m^2] (Warren, 2006). Halite/rocksalt typically has very low permeability in the range 10^{-6} mD (10^{-21} m^2) to 10^{-9} mD [10^{-24} m^2]; Dale & Hurtado, 1997; Beauheim & Roberts, 2002; Bérest & Brouard, 2003; Warren, 2006), with anhydrite $\approx 10^{-5}$ mD [10^{-20} m^2] (Beauheim & Roberts, 2002; Warren, 2006). Salt has such low permeabilities that it is thought possible that some of the permeability of the salt is induced by the cavern creation and operation (more precisely, either by tensile or high deviatoric stresses developed in the cavern wall, when the cavern fluid pressure is very high or very small – section 2.2.7.3.2.1 and Bérest & Brouard, 2003). As described above, typical well-formed cement in boreholes has very low permeability, of the order of 10^{-5} mD [10^{-20} m^2] (Nelson, 1990; Celia et al., 2006) and there will be no significant flow of gas unless there are preferential flow paths, the material has degraded, or the material was not emplaced properly.

There are what are referred to as slightly permeable salt formations. In these cases, the micropermeability of relatively high permeability salt (10^{-20} to 10^{-19} m^2) allows the brine pressure in a cavern to be very slowely released. Following the cavern reaching thermal equilibrium then a state can exist where the brine outflow toward the rock mass balances the volume loss due to creep. When salt formation permeability is smaller (<10^{-21} m^2), no significant pressure release occurs by brine permeation (Bérest & Brouard, 2003). However, 'secondary' permeability can be induced by high brine pressure in the cavern as tensile stresses at the cavern wall result in damage and a porosity/permeability (Fokker in Bérest & Brouard, 2003; also section 2.2.7.3.2.1).

Many good seals have entry pressures of more than 1000 psi, excellent seals have air-mercury entry pressures in excess of 3000 psi (PTTC, 2004). Typically, bedded evaporites, especially beds of predominantly monomineralic composition (e.g. massive halite/rocksalt), have entry pressures greater than 3000 psi, with impure evaporite beds having entry pressures greater than 1000 psi. The distance between salt (NaCl) lattice units is 2.8×10^{-10} m, while the smallest molecular diameter of a hydrocarbon molecule (methane) is 3.8×10^{-10} m (Warren, 2006). The entry pressures contrast with most shales (which are water bearing) showing typical entry pressures of 900-1000 psi (Warren, 2006).

Although shales form good seals, there is some diffusive leakage of methane (and some liquid hydrocarbons) with time via inherent microporosity. Evaporites, through a combination of the small size of molecular interspace in its ionically-bonded NaCl lattice, their ability to flow and anneal, make excellent long-term seals to substantial hydrocarbon columns, with little or no leakage of oil or gas, even by diffusion (Warren, 2006). The greater efficiency of evaporite seals is shown by the total hydrocarbon volumes held back by the two lithologies: total worldwide shale sediment volume is more than an order of magnitude greater than that of evaporites, yet the volumes of reservoired hydrocarbons below a shale or an evaporite seal is roughly 50:50 (Grunau, 1987). When allied to their viscoplastic nature, halite (or rocksalt) thus also makes an ideal rock type in which to construct voids for gas storage.

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2.2.3 The process of drilling an exploration well/injection well, well completions and casing

This section provides a brief summary of the process of drilling a standard hydrocarbon exploration and production (or injection) well. For the less experienced reader more detailed information may be obtained at http://www.oilandgas.org.uk/issues/storyofoil/exploration-02.htm and http://www.glossary.oilfield.slb.com/ and Appendix 8.

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[2] In most oilfield applications, the millidarcy (mD; 0.001 Darcy), is used as a measure of permeability. Permeability is fundamentally a L^2 unit. In SI it is expressed in μm^2 and in conventional metric use as m^2 or cm^2. The conversion between oilfield and SI units is 1 Darcy = 9.87×10^{-13} m^2. In practical terms, 1 mD and 1 μm^2 are essentially equivalent (e.g. Warren, 2006).

Over 40 years of North Sea exploration means that a huge amount of experience exists in the drilling and completing of oil or gas exploration wells, which are covered by strict drilling practices. Drilling of wells is now a very sophisticated, carefully designed and monitored operation, with many safety measures built in, including blowout preventors that protect against drilling into unexpected high pressure gas layers. Gas injection wells are drilled and completed to the same way and to the same strict standards as exploration wells. In exploration wells, drilling fluid (also called "mud"), which is mainly water-based, is pumped continuously down the drillstring while drilling. This acts as a lubricant and washes up the rock cuttings, which are brought to the surface by the circulating drilling fluid outside the drill pipe helping to identify the levels drilled and the presence of hydrocarbons. Gas storage wells into salt bearing strata, the drilling fluids are required not to cause dissolution of the salt and is commonly a brine solution.

All wells, including those drilled for producing water or hydrocarbons, at least when first drilled have openhole sections, but may be completed in a number of ways. After the hole is drilled to a given depth, a steel pipe (casing) is placed down the hole and is secured with cement. The casing provides structural integrity to the newly drilled wellbore and prevent caving of the wellbore wall. In addition it isolates chemically differing zones and potentially dangerous high-pressure zones or formations with significantly different pressure gradients from each other and from the surface.

Casing in its simplest form is large-diameter steel pipe, generally in sections around 13 m (40 ft) length with a threaded connection at each end. It is available in a range of material grades and sizes, internal diameters of which typically range from 4" to 30". Casing forms a major structural component of the wellbore and is lowered into an open hole borehole (wellbore) and cemented in place in order to stabilize the wellbore. The casing is assembled as a series of casing joints to form a casing string of the required length and specification for the wellbore in which it is installed. It is not uncommon for modern wells to have between two and five sets of progressively smaller hole sizes, each cemented with casing. Typically, a well contains multiple intervals of casing successively placed within the previous casing run. The following casing strings and intervals are commonly used in an oil or gas well:

- Conductor casing - prevents collapse of the loose soil near the surface and varies in size from 18" to 30"
- Surface casing – its purpose is to isolate freshwater zones and prevent contamination during drilling and completion. Surface casing is the most strictly regulated due to these environmental concerns, which can include regulation of casing depth and cement quality. Typical surface casing size is 13⅜"
- Intermediate casing - may be required on deeper boreholes where necessary drilling mud weight to prevent blowouts may cause a hydrostatic pressure that can fracture deeper formations
- Production casing – hung from the surface as the smallest casing and is typically 9⅝"
- Production liner - a casing string that does not extend to the top of the wellbore but instead is anchored or suspended from inside the bottom of the previous casing string producing a substantial savings in steel and therefore capital costs. There is no difference between the casing joints themselves and the liner is typically 7" diameter, although many liners match the diameter of the production tubing
- Production tubing - few wells actually produce through casing, because producing fluids can corrode steel or form deposits such a asphaltenes or parrafins and the larger diameter can make flow unstable. Production tubing is therefore installed inside the last casing string and the tubing annulus is usually sealed at the bottom of the tubing by a packer. Production tubing is commonly run from the completed interval back to the surface. Tubing is easier to remove for maintenance, replacement, or for various types of workover operations. Tubing is significantly lighter than casing and does not require a drilling rig to run in and out of hole; smaller pulling units are used for this purpose

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Casing is usually manufactured from plain carbon steel that is heat-treated to varying strengths but may be specially fabricated of stainless steel, aluminium, titanium, fibreglass and other materials. Typically, a well contains multiple intervals of casing successively placed within the previous casing run.

In salt bearing sequences, casing can be inserted from above to below the top of the salt. This protects the upper salt beds if drilling is continued into underlying formations with fluids that might otherwise dissolve the salt.

2.2.4 Damage to gas storage wells and reservoir formations

Damage occurs to gas storage wells and the storage reservoir immediately adjacent to the well bore during normal operation. In the more than 350 U.S. storage reservoirs with a total of over 14,000 individual wells, gas-storage operators experience an average loss in deliverability of 5% over time (Yeager et al., 1998). Some of this damage, such as invasion and 'sanding' (material from some very soft or friable sandy poorly cemented formations is drawn into the wellbore during the pressure drop associated with withdrawal) are well known phenomena that also occur in oil and gas exploration and production wells. Significant amounts of solids, just as with the fluids standing in the bottom of a wellbore, are also known to decrease the deliverability of gas injection wells.

Other mechanisms are more specific to gas injection wells with Yeager et al. (1998) having identified four main types blocking pore spaces and causing formation damage (refer Fig. 3):

- Bacterial damage (see Chapter 7) - tests of fluids from reservoir intervals reveal sulphate-reducing bacteria and in some cases, acid-producing bacteria exist in many reservoirs. Sulphate reducing bacteria favour an anaerobic (oxygen-free) environment and may coexist with iron-reducing bacteria where even small amounts of oils and grease will provide nutrients for growth. Stagnant water and low-flow conditions such as those encountered at the bottom of the wellbore are ideal for bacterial growth.
- Inorganic precipitates, such as iron compounds (iron carbonate [siderite] and iron sulphides), salts (sodium chloride and/or calcium chloride), calcium carbonate and barium sulphate. The presence of iron compounds along with elemental sulphur is often a key to (and occurs in association with) the sulphate-reducing bacteria alluded to above (see also Chapter 7). Iron serves as a good electron acceptor for bacteria in the metabolism of sulphates. The presence of inorganic precipitates is influenced by 1) the type and quantity of fluids injected and withdrawn from the formation, 2) operating procedures, 3) presence of bacteria, and 4) reservoir characteristics such as temperature and pressure
- Hydrocarbons, organic residue and production chemicals - trace or very small amounts of hydrocarbon oils, ester compounds, and/or isobutylene materials have been found as a dark layer along the face of the wellbore, or as substances lining/plugging pore throats. These organic residues are assumed to be the result of compressor or lubricating oils and/or various production chemicals associated with gas delivery and injection
- Particulates - surfaces of sidewall cores show some degree of very fine material adhering to them (and thus the borehole walls), which is the product of the drilling and/or the injection process

All of these wellbore and formation problems can be overcome but require different stimulation methods to restore injectivity and deliverability. Over the years, a great deal of expertise, not just in gas storage but also in exploration and production operations, has been gained in the diagnosis of damage mechanisms and the design of stimulation techniques. Expert systems to diagnose formation damage and select the best treatments to rectify problems with gas storage wells are available (e.g. Xiong et al., 2001).

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2.2.5 Depleted oil/gasfields

In the majority of oil/gasfields, the oil and/or gas is held in a porous rock (reservoir - often a sandstone), whereby spaces (pores) exist between the grains of sand, which form an interconnecting network between the grains, providing permeability (Fig. 4a-c). Some oil/gasfields are developed in other lithologies including carbonates and fractured basement rocks. The porosity and permeability enables the hydrocarbons to move through the rock mass. As oil (and/or gas) is produced from the oil/gasfield, so the pressure in the reservoir declines. Depending upon the drive mechanism during oil or gas production (see section 2.2.5.3), the pore spaces of the reservoir rock may remain gas or oil filled, or water may invade the pore spaces of the reservoir, due largely to hydrodynamic gradients.

The existence of an oil/gasfield attests to the capability of a structure and rock sequences to trap and successfully retain (commercial) quantities of hydrocarbons over significant periods of geological time (many millions of years). Depleted oil/gasfields thus offer the potential for re-injecting and storing natural gas underground. In many instances, re-injecting gas is associated with an increase in pressure within the reservoir, which can also lead to a period of increased oil recovery.

Depleted oil and gas fields represent the most cost effective storage option and is regarded as representing the preferred method of underground storage in the UK (BSI, 1998a).

2.2.5.1 BS EN 1918-2:1998

Underground gas storage in depleting oil and gas fields is covered by a British (and European) Standard, which also explains the concept and requirements of developing such a facility (BSI, 1998a).

2.2.5.2 Background

Gas storage in depleted oil and gasfields is the most widespread method of storing natural gas in large quantities. Worldwide, depleted reservoirs currently number around 480 storage facilities, providing around 76% of gas storage volume (Table 2).

As indicated above, the first gas storage experiment was made in a gasfield in Welland County, Ontario (Canada) in 1915. The first gas storage facility in a depleted reservoir was built in 1916, using a gasfield in Zoar near Buffalo, New York (USA) and is still operational (WGC, 2006). By 1930, there were nine storage facilities in six different American states and prior to 1950, virtually all natural gas storage facilities were in depleted reservoirs (http://www.naturalgas.org/naturalgas/storage.asp).

Facilities have generally been developed in depleted gas reservoirs, although increasingly, depleted oil reservoirs are being commissioned for this purpose. In the latter case this often has the added bonus of a period of enhanced oil recovery (EOR). However, prior to developing gas storage in a depleted field, studies on the cap rock gas tightness and integrity and the deliverability of the reservoir (e.g. the required injection and production rates, possible damage to the reservoir formation during production) are essential.

2.2.5.3 Drive mechanisms and depleted reservoirs

Natural gas (and oil) may be produced form the reservoirs in two ways but which can span the range from:

- Depletion drive - reservoir pressure declines with gas production due to the lack of ingress of water from surrounding aquifers. In depletion-drive reservoirs, 90% or more of the gas can be produced because there is no invading water to kill the wells (e.g., Laherrère, 1997).

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- Water drive - gas remains in near-hydrostatic pressure as water flows into the reservoir from surrounding aquifers continuously while gas is produced. In such reservoirs, much of the gas present cannot be produced because gas wells "water out," a process by which water cones upward to the well preventing gas from entering the well thereby "killing" production. Such reservoirs typically only produce 60% or less of the original gas in place (e.g., Laherèrre, 1997).

In some fields gas is also produced by pumping from surface infrastructure, but this is clearly a less profitable way.

Regardless of whether a given reservoir is one of the two end-member types or falls somewhere in between, natural gas injection will always involve a pressure drop (ΔP) from the well to the reservoir (Oldenburg, 2006). The magnitude of ΔP depends on the rate at which gas is injected and the injectivity of the formation and for high-quality gas reservoirs will typically be on the order of 5-10 bars (75-150 psi). Injection will be easier in depletion drive reservoirs (because there is no water to displace). However, the low reservoir pressure creates the possibility of a large pressure drop between injection well and the reservoir (Oldenburg, 2006).

The drive mechanism might play a role in the safety assessment case in that higher injection pressures (with the attendant additional stresses on infrastructure and reservoir rock), would be required for water depletion fields compared to depletion drive fields.

2.2.5.4 The Process of Gas Storage

The concept and principle of developing a storage facility in a depleted (hydrocarbon) reservoir is relatively simple. Natural gas is injected into the small pore spaces of a subsurface porous, permeable rock (reservoir) formation that were originally hydrocarbon bearing (refer Fig. 4), building up a volume of compressed gas, which is then withdrawn at a later date via operating wells. Additional observation wells may be drilled. Storage can be cycled between the maximum and minimum operating pressures. The maximum pressure is suggested to be the original reservoir pressure at the time of discovery, as this represents the highest known pressure at which the caprock and trap trapped hydrocarbons. Functional recommendations for the design, construction and operation of underground storage facilities in European oil and gasfields are detailed in BS EN 1918-2:1998 (BS 1998a). For specific elements of an underground gas storage facility, e.g. wells and surface installations, existing petroleum industry standards and legislation are likely to be applied.

Below the minimum operating pressure, there exists a large quantity of cushion gas in the reservoir, which is to all intents and purposes is physically unrecoverable gas. The volume of cushion gas can represent up to half the maximum volume of gas in place (http://www.naturalgas.org/naturalgas/storage.asp). Depleted reservoirs, however, having already been filled with natural gas and/or oil, do not require the same levels of injection of gas: that gas already exists in the formation. Replacing the natural gas with an alternative cushion gas can reduce investment costs.

Once oil or gas has been produced from a reservoir formation the pore space formerly occupied by the hydrocarbons is filled by invading formation waters. The generally saline water is naturally present in the rocks and its movement is driven by (hydrodynamic) pressure gradients. However, the situation can be reached where once too much water has migrated into the reservoir rock, it is difficult to displace with the injected gas, requiring pressures that make storage uneconomical or that might fracture the rock.

2.2.5.5 Presence and Effects of Hydrogen Sulphide (H_2S) in Oilfields

Oil and natural gas (mainly methane) are the products of the thermal conversion of decayed organic matter (called kerogen) trapped in sedimentary rocks. Also present in natural gas are

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naturally occurring contaminants including water vapour, sand, oxygen, carbon dioxide, nitrogen, hydrogen sulphide (H_2S) and rare gases such as helium and neon, which have to be removed at natural gas processing facilities. H_2S is an extremely poisonous gas and a few seconds of exposure in concentrations of anywhere between 750 and 10,000 ppm can prove lethal to people and animals. H_2S is hazardous to rig workers and is also corrosive, causing sulphide stress-corrosion cracking of metals, which may require costly special production equipment such as stainless steel tubing. The presence of H_2S in an oilfield and, if exposed to the gas during oil and gas production, its possible impacts on human health, is likely to be a potential concern for potential UGS operators. In addition to the brief details here, further details of the effects and dangers of H_2S are provided in Appendix 8.

High-sulphur kerogens release H_2S during decomposition, which stays trapped within the oil and gas deposits and is frequently encountered in oilfields, often to high levels, as in west Texas (Schlumberger, 2007). During oil exploration and production, H_2S may enter drilling muds from subsurface formations and is also generated by sulphate-reducing bacteria in stored muds. Natural gas, or any other gas mixture which contains significant amounts of H_2S, is generally termed 'sour' if there are more than 5.7 milligrams of H_2S per cubic meter of natural gas. This is equivalent to approximately 4 ppm by volume (http://www.naturalgas.org/naturalgas/processing_ng.asp).

The H_2S is removed ('scrubbed') from the sour gas by a process commonly referred to as 'sweetening' at what are termed desulphurization plants. Removal of H_2S is normally done by absorption in an amine solution, while other methods include carbonate processes, solid bed absorbents (including solid desiccants like iron sponges) and physical absorption.

2.2.5.5.1 Effects of H_2S

H_2S variously acts as an irritant or an asphyxiant, depending of the concentration of the gas and the length of exposure. The primary route by which humans are affected is inhalation, although it also affects the eyes. Essentially, H_2S blocks cellular respiration, resulting in cellular anoxia, a state in which the cells do not receive oxygen and die. Some scientific references have reported exposure to concentrations of H_2S as low as one part per million can affect the central nervous system, resulting in neuropsychological effects (e.g. Chilingar & Endres, 2005), however, there is not scientific consensus on this point (UNEP[3]: http://www.uneptie.org/pc/apell/disasters/china_well/china.htm#impacts). At levels up to 100 to 150 ppm, H_2S is a tissue irritant, causing Keratoconjunctivitis (combined inflammation of the cornea and conjunctiva), respiratory irritation with lachrymation (tears) and coughing. Skin irritation is also a common symptom. Instantaneous loss of consciousness, rapid apnea (slowed or temporarily arrested breathing) and death may result from acute exposure to levels above 1,000 ppm (Knight & Presnell, 2005; Skrtic, 2006).

The non-lethal effects can be summarized as:

- *neurological* –symptoms including dizziness, vertigo, agitation, confusion, headache, tremors, nausea, vomiting, convulsions, dilated pupils, and unconsciousness,
- *pulmonary* – symptoms including cough, chest tightness, dyspnea (shortness of breath), cyanosis (turning blue from lack of oxygen), haemoptysis (spitting or coughing up blood), pulmonary oedema (fluid in the lungs), and apnea with secondary cardiac effects (Snyder et al., 1995).

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[3] UNEP: United Nations Environment Programme

2.2.5.5.2 Incident at Gasfield, Chongquing, China

An incident in China illustrates the potentially deadly effects of H_2S release during production from a gasfield. The disaster took place at the Chuandongbei gas field in Gao Qiao town in the north eastern part of Chongqing province. The incident involved a gas well blowout, which occurred at 10:00 pm on Tuesday, 23 December 2003 and resulted in the release of natural gas and H_2S. According to press reports, the accident occurred as a drilling team was working on the 400 meter deep well and sent toxic fumes (sour gas - a high concentration of natural gas and H_2S) shooting 30 metres out of a failed well (UNEP: http://www.uneptie.org/pc/apell/disasters/china_well/china.htm#impacts).

The *China Daily* newspaper described the tragedy as "the worst of its kind in China's history". "The poisonous gas hovering in the air made an area of 25 square kilometres a death zone, as many villagers were intoxicated by the fumes in their sleep". Worst hit was the village of Xiaoyang next to the gas well, where 90% (c. 243) of the residents were killed, "many having died in their sleep or were too old to escape". More than 9,000 people were treated for injuries and 60,000 were forced to evacuate the area. (WSWS, 2003; Lloyd's Casualty Week for 23rd Jan 2003).

Many factors appear to have led to the release, most related to human error and poor operational and maintenance procedures, including operation under health and safety regulations that were far less stringent than those established in the UK.

2.2.5.5.3 In the UK context

Gas imported into an oilfield will be 'sweet', having been previously processed for the National Grid and would, therefore, have low H_2S levels (no higher than about 3 ppm). Injection of this gas into an oilfield with H_2S present would lead to its absorption (along with water), which on withdrawal would require the gas to be processed with removal of the H_2S and water. To some extent, injecting large volumes of 'sweet gas' would potentially dilute the H_2S levels in an oilfield, but levels in the subsequently withdrawn gas would be higher than prior to injection. The levels of absorption are likely to be determined by the time the gas is held in storage, which is likely to be for a period of 3-6 months or more.

The presence of H_2S in oilfields considered for gas storage in the East Midlands has been raised as a concern by local residents and local District and County councillors (Davidson, in press). A number of oilfields in the East Midlands region are termed 'sour', i.e. the associated gas produced at some oilfields, such as Welton, has high concentrations of H_2S. Supplementary information submitted by Star Energy to Lincolnshire County Council for the Welton Planning Application gave a figure of 3079 ppm by volume for H_2S in the Welton oilfield and that processes to remove ('scrub') the gas currently being produced were already in place. However, higher levels of H_2S, typically between 5,000 ppm and 10,000 ppm, with peaks as high as 15,000 ppm were recorded during trials on a 'fixed-bed' compact catalytic converter at the Welton oilfield in 1987 (Eddington & Carnell, 1991). This equipment is installed on vents (the first being in 1989 with others added later), and has no operating requirements other than routine analysis and removes between 92% and 100% of the H_2S. The H_2S is removed from the gas stream by reaction with the absorbent to form stable metal sulphides, with no impurities added to the gas stream. The 'spent' absorbent is nonhazardous and is discharged in the form of granules, which can be disposed of through the metal recovery industry (Eddington & Carnell, 1991).

H_2S is reported in other UK oil and gasfields, but can be very variable in its concentrations. For example at Caythorpe, the upper tight (Permian) dolomite reservoir contains gas with an H_2S content of around 5 parts per million (ppm). The lower main producing (Early Permian) Rotliegend gas reservoir has no reported H_2S content (IEA, 1999).

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The presence of H_2S at any particular proposed UK oilfield UGS site during the oil production phase might, therefore, require particular attention, assessment and precautions in the operational plans and proposals on a site-by-site basis. However, in 1997, an atlas of the composition and isotope ratios of natural gases in northwest European gasfields in the Southern Permian Basin was produced under the European Commission JOULE Programme (Lokhorst, 1997). This provided contoured maps of the levels of the main gases around the basin. H_2S is reported in other UK oil and gasfields, but can be very variable in its concentrations. The study provides important information on the levels of H_2S in UK oil and gasfields. Given the common source of the gas (Westphalian), this information may be of importatnce to onshore fields in the first instance when assessing the regional trends.

2.2.5.6 Susidence associated with oil and gas production

Subsidence associated with oil and gas production is a well-known phenomenon and one that nowadays is predictable and can be modelled. Fluid production and declining reservoir (pore) pressures may lead to a 'relaxation' of the reservoir. This movement may propagate to the surface, being typically manifested as a bowl-shaped subsidence (depression) at the surface, centred over the oilfield. The subject and summaries of problems of subsidence encountered at oilfield sites is considered in more detail in Chapter 8.

2.2.6 Aquifers

Aquifer storage is based up on the same concepts as depleting oil/gasfields, but represents a more costly option as aquifers require conditioning and more preliminary work to prove the capability to hold and contain gas under pressure and a greater investment in cushion gas as the reservoir formerly held saline waters (e.g. Oldenburg, 2002; Favret, 2003). Traditionally, these facilities are operated with a single winter withdrawal period, although they may be used to meet peak load requirements as well. In the UK context (and generally), aquifer storage represents the least desirable and most expensive type of natural gas storage facility for a number of reasons, perhaps most crucially, that there are likely to be environmental restrictions to using aquifers as natural gas storage.

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Though not considered further in this assessment of UK underground gas storage, a brief background of aquifer storage is provided for information and completeness.

2.2.6.1 BS EN 1918-1:1998

Underground gas storage in aquifers is covered by a British (and European) Standard, which also explains the concept and requirements of developing such a facility (BSI, 1998b).

2.2.6.2 Background

Aquifers are underground porous, permeable rock formations that act as natural water reservoirs and were first used for gas storage in 1946 in Kentucky, USA (Favrez, 2003). They are around 80 storage facilities in aquifers in the world today, most of them in the United States, the former Soviet Union and Western Europe (France, Germany and Italy). France has around 12 aquifer storage facilities.

The principle of aquifer storage is to create an artificial gasfield by 'reconditioning' the water-bearing formations and injecting gas into the water-bearing pore spaces (refer to oil and gas scenario; Fig 4a-c). While natural gas being stored in aquifers has already undergone all of its processing, upon extraction from a water-bearing aquifer formation the gas typically requires further dehydration prior to transporting, which requires specialized equipment on site near the wellhead.

However, aquifers do not have the immediate advantages that converting depleted oil/gasfields into a storage facilities has because hydrocarbons have generally not previously been trapped in the rocks (unless the trap has been breached, in which case it may not represent an ideal storage site anyway). The geological characteristics of aquifer formations are not as well known and as a result, a greater amount of site characterisation is necessary to establish the suitable geological conditions exist for gas storage, including reservoir, structure and suitable caprock. Furthermore, aquifer storage creates pressure gradients that the storage and caprock formations have not previously experienced. This could result in failure of the caprock due to the displacement of the static water column, forcing water out of the caprock and permitting gas to leak from the storage formation. This process is known as exceeding the threshold displacement pressure or threshold pressure (Lippman & Benson, 2003; see also section 3.4).

2.2.7 Salt caverns

Rock salt (halite; NaCl) exhibits unique physical properties and mechanical behaviour. Halite beds in situ are extremely soluble, highly incompressible and are thought to be almost impermeable below about 300 m (Baar, 1977). Such beds are nonporous and are known to provide the regional seal to economic accumulations of hydrocarbons. They also represent a unique host material for the development of (large) caverns and storage of materials that do not cause dissolution of the salt.

Rock salt may exist in two forms. It is deposited in sedimentary layers forming a series of bedded deposits (so called 'thin bedded' salt, Fig 4d). The salt is highly ductile and during burial beneath younger sediments and due to its rheological and deformation mechanisms forms a weak layer between other more competent lithologies and deforms readily by ductile (plastic) creep (refer section 4.2). Under geological timescales and geostatic pressures, it deforms ('flows') plastically, much like a viscous fluid and salt is often viewed as a pressurized fluid. This process is known as halokinesis and can give rise to a series of halokinetic structures (so called 'massive' salt), ranging from salt swells to pillows to larger, salt domes (Fig. 4d) and elongate salt wall structures. Salt domes can reach up to 1.6 km in diameter and anywhere between 5 and 9 km in height.

Rather than fracturing, most halite beds lose their seal integrity either through dissolution windows or through salt-flow induced breaches, known as 'overburden touchdown' or salt welds. This occurs when salt flows to a region (thickens) and as it does so is withdrawn from adjacent areas, where it consequently thins. Thick salt beds experience brittle fracture only at very shallow near surface levels and typically vadose conditions or perhaps during very high strain rates, as might be associated with major faults defining sedimentary basins. There are, however, no such active faults in the UK at present (refer section 6.2).

The preservation of soluble bedded salt (and salt in halokinetic structures) over long periods of geological time demonstrates the relatively inactive hydrological settings in which it is found. On the other hand, should salt beds come into contact with circulating groundwaters then its high solubility in water means that salt deposits can be subject to rapid degradation. The same high solubility, however, also permits the rapid creation of caverns at relatively low cost. The low permeability of salt means that should any stored material leak from the cavern, then transport away from the facility would generally be slow (Hovorka, 2000). The storage capacity for a given cavity volume (varying from several hundreds of thousands to millions of cubic metres) is proportional to the maximum operating pressure, which is dependent upon the depth from the surface.

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The physical properties and characteristics of rocksalt offer another option for the underground storage of hydrocarbon products (including LPG and natural gas). Salt cavities may be excavated in bedded salt layers or in halokinetic structures, with two scenarios existing for UFS:

- Abandoned salt mines. These were not originally constructed (or operated) with gas storage in mind. Former salt mines, which are used in the USA for underground fuel storage, tend to be at shallower depths than those at which solution mined cavities are constructed, with the inherent problems of thinner cap rock and possible groundwater interaction
- Solution mined caverns. Many early storage caverns were originally created by solution-mining during the production of brine and chlorine products. They have subsequently been used for the storage of a range of products, including natural gas. However, the completed brine cavities were not ideally designed or constructed (in terms of their shape or spacing) for high-pressure gas storage. Gas cavities should be spherical or cylindrical in shape with domed roofs and with a grid spacing related to their size (diameter). In the UK during the 1920s, ICI was at the forefront of the development of techniques for solution mining and salt extraction at their operations in the Preesall Saltfield (e.g. Wilson & Evans, 1990; Hortholt & Highley, 1973; Evans & Holloway, in press). However, the early ICI caverns often saw the almost complete removal of salt in a cavern, leaving little or no roof salt protecting the overlying nonsalt beds. These caverns generally collapsed, but as the technique was improved and knowledge of salt mechanics grew, so to did brining techniques. This led to the production of more stable caverns, particularly on abandonment. The technique of the design and solution mining of salt cavities in bedded or domal salt structures for the purpose of high-pressure gas storage is now well advanced. The design and construction of caverns specifically for gas storage is now at such a stage that a process termed solution mining under gas (SMUG) is performed – storage of product begins as creation of the remaining cavity continues (e.g. Chabrelie, et al., 1998 – and section 2.2.7.3.2).

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In England, there are an increasing number of proposals to design and construct salt cavern facilities for the purposes of underground storage of natural gas. Salt cavern facilities generally serve to store smaller volumes of gas than those that can be stored in aquifers or depleted reservoirs, although the larger cavern facilities with 10's of caverns can provide storage volumes approaching those of small oil/gasfields. Importantly, however, salt cavern storage facilities complement large porous reservoir storage, offering several advantages including high deliverability and degree of availability, short filling period and low percentage of cushion gas (which can be almost completely recovered on abandonment of the facility). Thus the combination of the two types of storage, in porous reservoirs, which are generally used to guarantee basic demand to meet seasonal variations, and storage in salt cavities, which are generally operated to cover peak demand, allows high withdrawal rates even at the end of the withdrawal period.

Whilst halite with its extremely low permeability and general viscoplastic deformation is viewed as an ideal storage medium, there are examples of salt having suffered brittle deformation, with the indication that long-range migration of methane has occurred through the fractures (Terrinha et al., 1994; Davison et al., 1996a). This has potentially important implications for not only hydrocarbon potential of basins but also gas storage and is reviewed further in section 6.1.4.

In this report the main incidents at storage facilities that caused injuries or casualties and what were believed to be the factors and causes behind their occurrence are briefly reviewed. One or two examples of salt cavern storage facilities had to close due to volume loss and these are included for completeness. However, it is stressed that these latter incidents were not associated with cavern failure, release of stored material or any loss of life or injury. Furthermore, there are few cases of catastrophic failure (collapses) known and caverns do not, in general, fail catastrophically or close rapidly when depressurized for short periods of time. Most cavities are

geologically represents a very different environment to the UK, but has attracted interest in terms of safety records.

Chapter 10 outlines the incidents and casualty rates from the oil and gas production/supply chain and petrochemical industries and contained in two or three major reports. This includes the casualty rates involved in the supply of domestic gas in the UK and USA, and is aimed at providing some means of assessing the incident and casualty levels in UFS described in Chapter 9.

From the preceding chapters and descriptions of incidents, Chapter 11 summarises the main risks and release scenarios when considering UFS and UGS and provides a framework and list of parameters for risk analysis and assessment. The background information and considerations are contained in Appendix 6. The chapter discusses the risks in UGS in general and what might be seen as the additional main issues relating to gas storage in salt caverns. The risk assessment parameters for consideration in risk analysis/assessment of UK scenarios are then developed and summarised, with Appendix 7 containing detailed parameters for the various identified UK scenarios. These findings were then input into a sister study undertaken by Quintessa defining the Features, Events and Processes (FEPs) relative to UGS and which has undertaken scoping calculations for gas release from potential UK UGS scenarios (Watson et al., 2007).

Chapter 12 draws together the various findings of this report to produce a summary of the main risks associated with UGS and considerations in the UK context of UGS.

To keep the main report as short as possible, much of the supporting information and detailed descriptions of, for example, the various problems and incidents at existing salt mines or brinefields and reported during UFS operations, are included in Appendices 1 to 7. Should the reader require further information on certain aspects then they are referred to these more detailed summaries at the back of the report.

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case of abandoned mines, have proved problematical with leakage of stored product through cap rock sequences.

As alluded to above, worldwide there are around 630 UGS facilities currently operational (Table 2). The US operates the highest number, with 394 (although 37 were classified as marginal at the end of 2005 – that is no injections or withdrawals, or withdrawals only were made; EIA, 2006). This figure compares with 410 underground natural gas storage facilities in operation in 1998 and a peak figure of 418 operational sites in 2001. Between 1998 and 2005, 42 facilities were abandoned as uneconomic or defective, while 26 new sites were placed in operation (EIA, 2006). Europe has around 120 facilities currently operational.

The vast majority of UGS facilities are developed in depleted (or depleting) oil/gasfields (478 or 76%), with those in aquifers (80 or 13%) outnumbering those in salt caverns (66 or 11%). Other facilities (abandoned mines or lined rocks caverns) represent negligible percentages.

Most depleted reservoir storage facilities are designed to be cycled only once each year and typically require between 70 and 200 days to refill (EIA, 1995; Plaat, in press). In contrast, salt cavern facilities are designed with the intent of cycling the entire working gas capacity perhaps 5 to 10 times each year. Typical injection periods are in the range of 20 days.

The factors that determine whether or not a depleted reservoir or salt cavern storage facility will make a suitable storage facility are both geographical and geological. Geographically, potential sites would, ideally, be relatively close to the consuming regions or industry. They must also be close to transport infrastructure, including main and trunk pipelines and distribution systems. Geologically, pore storage options (depleted oil and gasfields and aquifers) require good porosity and permeability. The porosity of the formation determines the amount of natural gas that it may hold. The permeability determines the rate at which natural gas flows through the rock formation, which in turn determines the rate of injection and withdrawal of working gas. Together, the porosity and permeability of reservoirs determine the effectiveness or performance and thus economic viability of any specific site. Depleted hydrocarbon reservoirs, because they have held and produced hydrocarbons, tend to have high permeability and porosity. They have also proved the integrity of the trap to retain hydrocarbons over geological time (millions of years). This is different for aquifer storage, where the porosity, permeability and cap rock all have to be proven, which is more expensive and impacts upon the viability of any proposed development.

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2.2.1 Basic concepts, 'working' and 'cushion' gases

More detailed and specific characteristics of depleted reservoirs, aquifers, and salt caverns are outlined below (and can be obtained at http://www.naturalgas.org/naturalgas/storage.asp), but essentially, an underground storage facility is prepared ("reconditioned") prior to injection, to effectively create an underground, pressurised storage container. In the case of depleted oil/gasfields or aquifers, natural gas is injected into the interconnected pore spaces that exist between the constituent grains that make up the formation (and which have not been infilled by microbes or cementing minerals such as clays and quartz – section 2.2.4), whilst in salt caverns it is injected into the void created in the salt, building up pressure as more natural gas is added. As in the case of newly drilled oil or gas wells, the higher the pressure in the storage facility, the more readily gas may be extracted. Once the pressure drops to below that of the wellhead, no pressure differential exists to 'push' the natural gas out of the storage facility.

Two types of gas are referred to in storage terms:

- Working gas (sometimes called the working volume), is the maximum volume of gas available for withdrawal during the normal operation of the storage facility. Obviously, this is greatest when the facility has been filled to capacity. The capacity of storage facilities normally refers to their working gas capacity.

reservoir with CO_2, it would also provide a method of carbon sequestration (e.g. Oldenburg, 2002).

Whilst CO_2 injection has been employed in many instances to improve production of oilfields, studies on the site specific CO_2-rock interactions might be required to assess the likely impact of the CO_2 on both reservoir and caprock sequences. CO_2 could, for example, cause drying out of caprock shales, thereby altering the physical properties and strength, potentially leading to cracks and leakage pathways for gas.

In some salt caverns, a diesel blanket is used to provide protection against further leaching of the already constructed cavern roof and sides. However, it can also be used as an injected material when the cavities are operated in 'compensated mode' like that of brine compensated withdrawal and injection. It represents a more expensive option to brine, but would not carry the potential dangers of further salt solution and enlargement of the cavern (should the solution rate be faster than the salt creep processes).

2.2.2 Permeabilities and capillary entry pressures of well cement, shale and salt

As would be expected, a vast literature exists on the various well cements developed in the oil and gas exlporation, geothermal and waste well sectors and this cannot be reviewed here. However, an excellent entry to well cementing is provided by Nelson (1990). It is to be reasonably expected that any prospective operators of gas storage facilities will have designed the construction and completions of wells to the standards used in the oil and gas sectors: experience in these industries having been acquired over more than 100 years.

Those wells penetrating salt-prone sequences or aiming to develop salt caverns should meet the requirements of the drilling fluids not to dissolve the host salt and to obtain gas-tight well completions (bond between well cement and the borehole walls and well casing). On the latter point one study on the bond strength between the cement plug and host rock in abandoned boreholes is worthy of note (Akgün, 1997). Under testing, dissolution along the interface of the cement and the salt was observed, reducing bond strength. This might have been enhanced by clay inclusions in the salt. Gaining detailed information on the purity of halites beds might, therefore, be an area of extra consideration when assessing bedded salt successions in the UK.

Studies of potential for leakage of cement bondings in wells for CO_2 injection and storage have shown that degraded segments of well cements might have permeabilities of 10^{-1} mD [10^{-16} m^2] (Celia et al., 2006). To produce significant leakage (1% fraction CO_2), the effective permeability associated with the well must increase to about 10^5 mD (101 Darcy [10^{-10} m^2]), which is many orders of magnitude larger than the permeability of intact cement (10^{-5} mD [10^{-20} m^2]; Nelson, 1990; Celia et al., 2006). This illustrates clearly that in this case, well-formed cement will not leak any CO_2 (Scherer et al., 2005). Based upon these data, less than well-formed cement behind well casings is more permeable than any evaporite bed that an oil or gas injection well intersects

Important to the concept of gas storage are the permeabilities and capillary entry pressures of the caprock or containing rock type. Capillary pressure in rocks is the pressure at which the nonwetting phase first displaces the wetting phase and is controlled by interfacial tension between grains, 'wettability', and the pore throat size distribution (section 3.4). The seal capacity is the maximum hydrocarbon column height that a seal can trap, which is controlled by the capillary entry pressure.

Salts may be both a storage medium (caverns) and provide seals to economic accumulations of hydrocarbons. Gas hydrates (clathrates) aside, salts (and associated evaporites) provide the most effective seal to hydrocarbon traps, regardless of hydrocarbon type and structural setting (Downey, 1984; Warren, 2006). Evaporite seals have very high entry pressures, very low permeabilities and large lateral extents and maintain seal integrity over wide areas and a range of

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Over 40 years of North Sea exploration means that a huge amount of experience exists in the drilling and completing of oil or gas exploration wells, which are covered by strict drilling practices. Drilling of wells is now a very sophisticated, carefully designed and monitored operation, with many safety measures built in, including blowout preventors that protect against drilling into unexpected high pressure gas layers. Gas injection wells are drilled and completed to the same way and to the same strict standards as exploration wells. In exploration wells, drilling fluid (also called "mud"), which is mainly water-based, is pumped continuously down the drillstring while drilling. This acts as a lubricant and washes up the rock cuttings, which are brought to the surface by the circulating drilling fluid outside the drill pipe helping to identify the levels drilled and the presence of hydrocarbons. Gas storage wells into salt bearing strata, the drilling fluids are required not to cause dissolution of the salt and is commonly a brine solution.

All wells, including those drilled for producing water or hydrocarbons, at least when first drilled have openhole sections, but may be completed in a number of ways. After the hole is drilled to a given depth, a steel pipe (casing) is placed down the hole and is secured with cement. The casing provides structural integrity to the newly drilled wellbore and prevent caving of the wellbore wall. In addition it isolates chemically differing zones and potentially dangerous high-pressure zones or formations with significantly different pressure gradients from each other and from the surface.

Casing in its simplest form is large-diameter steel pipe, generally in sections around 13 m (40 ft) length with a threaded connection at each end. It is available in a range of material grades and sizes, internal diameters of which typically range from 4" to 30". Casing forms a major structural component of the wellbore and is lowered into an open hole borehole (wellbore) and cemented in place in order to stabilize the wellbore. The casing is assembled as a series of casing joints to form a casing string of the required length and specification for the wellbore in which it is installed. It is not uncommon for modern wells to have between two and five sets of progressively smaller hole sizes, each cemented with casing. Typically, a well contains multiple intervals of casing successively placed within the previous casing run. The following casing strings and intervals are commonly used in an oil or gas well:

- Conductor casing - prevents collapse of the loose soil near the surface and varies in size from 18" to 30"
- Surface casing – its purpose is to isolate freshwater zones and prevent contamination during drilling and completion. Surface casing is the most strictly regulated due to these environmental concerns, which can include regulation of casing depth and cement quality. Typical surface casing size is 13⅜"
- Intermediate casing - may be required on deeper boreholes where necessary drilling mud weight to prevent blowouts may cause a hydrostatic pressure that can fracture deeper formations
- Production casing – hung from the surface as the smallest casing and is typically 9⅝"
- Production liner - a casing string that does not extend to the top of the wellbore but instead is anchored or suspended from inside the bottom of the previous casing string producing a substantial savings in steel and therefore capital costs. There is no difference between the casing joints themselves and the liner is typically 7" diameter, although many liners match the diameter of the production tubing
- Production tubing - few wells actually produce through casing, because producing fluids can corrode steel or form deposits such a asphaltenes or parrafins and the larger diameter can make flow unstable. Production tubing is therefore installed inside the last casing string and the tubing annulus is usually sealed at the bottom of the tubing by a packer. Production tubing is commonly run from the completed interval back to the surface. Tubing is easier to remove for maintenance, replacement, or for various types of workover operations. Tubing is significantly lighter than casing and does not require a drilling rig to run in and out of hole; smaller pulling units are used for this purpose

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2.2.5 Depleted oil/gasfields

In the majority of oil/gasfields, the oil and/or gas is held in a porous rock (reservoir - often a sandstone), whereby spaces (pores) exist between the grains of sand, which form an interconnecting network between the grains, providing permeability (Fig. 4a-c). Some oil/gasfields are developed in other lithologies including carbonates and fractured basement rocks. The porosity and permeability enables the hydrocarbons to move through the rock mass. As oil (and/or gas) is produced from the oil/gasfield, so the pressure in the reservoir declines. Depending upon the drive mechanism during oil or gas production (see section 2.2.5.3), the pore spaces of the reservoir rock may remain gas or oil filled, or water may invade the pore spaces of the reservoir, due largely to hydrodynamic gradients.

The existence of an oil/gasfield attests to the capability of a structure and rock sequences to trap and successfully retain (commercial) quantities of hydrocarbons over significant periods of geological time (many millions of years). Depleted oil/gasfields thus offer the potential for re-injecting and storing natural gas underground. In many instances, re-injecting gas is associated with an increase in pressure within the reservoir, which can also lead to a period of increased oil recovery.

Depleted oil and gas fields represent the most cost effective storage option and is regarded as representing the preferred method of underground storage in the UK (BSI, 1998a).

2.2.5.1 BS EN 1918-2:1998

Underground gas storage in depleting oil and gas fields is covered by a British (and European) Standard, which also explains the concept and requirements of developing such a facility (BSI, 1998a).

2.2.5.2 Background

Gas storage in depleted oil and gasfields is the most widespread method of storing natural gas in large quantities. Worldwide, depleted reservoirs currently number around 480 storage facilities, providing around 76% of gas storage volume (Table 2).

As indicated above, the first gas storage experiment was made in a gasfield in Welland County, Ontario (Canada) in 1915. The first gas storage facility in a depleted reservoir was built in 1916, using a gasfield in Zoar near Buffalo, New York (USA) and is still operational (WGC, 2006). By 1930, there were nine storage facilities in six different American states and prior to 1950, virtually all natural gas storage facilities were in depleted reservoirs (http://www.naturalgas.org/naturalgas/storage.asp).

Facilities have generally been developed in depleted gas reservoirs, although increasingly, depleted oil reservoirs are being commissioned for this purpose. In the latter case this often has the added bonus of a period of enhanced oil recovery (EOR). However, prior to developing gas storage in a depleted field, studies on the cap rock gas tightness and integrity and the deliverability of the reservoir (e.g. the required injection and production rates, possible damage to the reservoir formation during production) are essential.

2.2.5.3 Drive mechanisms and depleted reservoirs

Natural gas (and oil) may be produced form the reservoirs in two ways but which can span the range from:

- Depletion drive - reservoir pressure declines with gas production due to the lack of ingress of water from surrounding aquifers. In depletion-drive reservoirs, 90% or more of the gas can be produced because there is no invading water to kill the wells (e.g., Laherrère, 1997).

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naturally occurring contaminants including water vapour, sand, oxygen, carbon dioxide, nitrogen, hydrogen sulphide (H_2S) and rare gases such as helium and neon, which have to be removed at natural gas processing facilities. H_2S is an extremely poisonous gas and a few seconds of exposure in concentrations of anywhere between 750 and 10,000 ppm can prove lethal to people and animals. H_2S is hazardous to rig workers and is also corrosive, causing sulphide stress-corrosion cracking of metals, which may require costly special production equipment such as stainless steel tubing. The presence of H_2S in an oilfield and, if exposed to the gas during oil and gas production, its possible impacts on human health, is likely to be a potential concern for potential UGS operators. In addition to the brief details here, further details of the effects and dangers of H_2S are provided in Appendix 8.

High-sulphur kerogens release H_2S during decomposition, which stays trapped within the oil and gas deposits and is frequently encountered in oilfields, often to high levels, as in west Texas (Schlumberger, 2007). During oil exploration and production, H_2S may enter drilling muds from subsurface formations and is also generated by sulphate-reducing bacteria in stored muds. Natural gas, or any other gas mixture which contains significant amounts of H_2S, is generally termed 'sour' if there are more than 5.7 milligrams of H_2S per cubic meter of natural gas. This is equivalent to approximately 4 ppm by volume (http://www.naturalgas.org/naturalgas/processing_ng.asp).

The H_2S is removed ('scrubbed') from the sour gas by a process commonly referred to as 'sweetening' at what are termed desulphurization plants. Removal of H_2S is normally done by absorption in an amine solution, while other methods include carbonate processes, solid bed absorbents (including solid desiccants like iron sponges) and physical absorption.

2.2.5.5.1 Effects of H_2S

H_2S variously acts as an irritant or an asphyxiant, depending of the concentration of the gas and the length of exposure. The primary route by which humans are affected is inhalation, although it also affects the eyes. Essentially, H_2S blocks cellular respiration, resulting in cellular anoxia, a state in which the cells do not receive oxygen and die. Some scientific references have reported exposure to concentrations of H_2S as low as one part per million can affect the central nervous system, resulting in neuropsychological effects (e.g. Chilingar & Endres, 2005), however, there is not scientific consensus on this point (UNEP[3]: http://www.uneptie.org/pc/apell/disasters/china_well/china.htm#impacts). At levels up to 100 to 150 ppm, H_2S is a tissue irritant, causing Keratoconjunctivitis (combined inflammation of the cornea and conjunctiva), respiratory irritation with lachrymation (tears) and coughing. Skin irritation is also a common symptom. Instantaneous loss of consciousness, rapid apnea (slowed or temporarily arrested breathing) and death may result from acute exposure to levels above 1,000 ppm (Knight & Presnell, 2005; Skrtic, 2006).

The non-lethal effects can be summarized as:

- *neurological* –symptoms including dizziness, vertigo, agitation, confusion, headache, tremors, nausea, vomiting, convulsions, dilated pupils, and unconsciousness,
- *pulmonary* – symptoms including cough, chest tightness, dyspnea (shortness of breath), cyanosis (turning blue from lack of oxygen), haemoptysis (spitting or coughing up blood), pulmonary oedema (fluid in the lungs), and apnea with secondary cardiac effects (Snyder et al., 1995).

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[3] UNEP: United Nations Environment Programme

The presence of H_2S at any particular proposed UK oilfield UGS site during the oil production phase might, therefore, require particular attention, assessment and precautions in the operational plans and proposals on a site-by-site basis. However, in 1997, an atlas of the composition and isotope ratios of natural gases in northwest European gasfields in the Southern Permian Basin was produced under the European Commission JOULE Programme (Lokhorst, 1997). This provided contoured maps of the levels of the main gases around the basin. H_2S is reported in other UK oil and gasfields, but can be very variable in its concentrations. The study provides important information on the levels of H_2S in UK oil and gasfields. Given the common source of the gas (Westphalian), this information may be of importatnce to onshore fields in the first instance when assessing the regional trends.

2.2.5.6 Susidence associated with oil and gas production

Subsidence associated with oil and gas production is a well-known phenomenon and one that nowadays is predictable and can be modelled. Fluid production and declining reservoir (pore) pressures may lead to a 'relaxation' of the reservoir. This movement may propagate to the surface, being typically manifested as a bowl-shaped subsidence (depression) at the surface, centred over the oilfield. The subject and summaries of problems of subsidence encountered at oilfield sites is considered in more detail in Chapter 8.

2.2.6 Aquifers

Aquifer storage is based up on the same concepts as depleting oil/gasfields, but represents a more costly option as aquifers require conditioning and more preliminary work to prove the capability to hold and contain gas under pressure and a greater investment in cushion gas as the reservoir formerly held saline waters (e.g. Oldenburg, 2002; Favret, 2003). Traditionally, these facilities are operated with a single winter withdrawal period, although they may be used to meet peak load requirements as well. In the UK context (and generally), aquifer storage represents the least desirable and most expensive type of natural gas storage facility for a number of reasons, perhaps most crucially, that there are likely to be environmental restrictions to using aquifers as natural gas storage.

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Though not considered further in this assessment of UK underground gas storage, a brief background of aquifer storage is provided for information and completeness.

2.2.6.1 BS EN 1918-1:1998

Underground gas storage in aquifers is covered by a British (and European) Standard, which also explains the concept and requirements of developing such a facility (BSI, 1998b).

2.2.6.2 Background

Aquifers are underground porous, permeable rock formations that act as natural water reservoirs and were first used for gas storage in 1946 in Kentucky, USA (Favrez, 2003). They are around 80 storage facilities in aquifers in the world today, most of them in the United States, the former Soviet Union and Western Europe (France, Germany and Italy). France has around 12 aquifer storage facilities.

The principle of aquifer storage is to create an artificial gasfield by 'reconditioning' the water-bearing formations and injecting gas into the water-bearing pore spaces (refer to oil and gas scenario; Fig 4a-c). While natural gas being stored in aquifers has already undergone all of its processing, upon extraction from a water-bearing aquifer formation the gas typically requires further dehydration prior to transporting, which requires specialized equipment on site near the wellhead.

The physical properties and characteristics of rocksalt offer another option for the underground storage of hydrocarbon products (including LPG and natural gas). Salt cavities may be excavated in bedded salt layers or in halokinetic structures, with two scenarios existing for UFS:

- Abandoned salt mines. These were not originally constructed (or operated) with gas storage in mind. Former salt mines, which are used in the USA for underground fuel storage, tend to be at shallower depths than those at which solution mined cavities are constructed, with the inherent problems of thinner cap rock and possible groundwater interaction
- Solution mined caverns. Many early storage caverns were originally created by solution-mining during the production of brine and chlorine products. They have subsequently been used for the storage of a range of products, including natural gas. However, the completed brine cavities were not ideally designed or constructed (in terms of their shape or spacing) for high-pressure gas storage. Gas cavities should be spherical or cylindrical in shape with domed roofs and with a grid spacing related to their size (diameter). In the UK during the 1920s, ICI was at the forefront of the development of techniques for solution mining and salt extraction at their operations in the Preesall Saltfield (e.g. Wilson & Evans, 1990; Hortholt & Highley, 1973; Evans & Holloway, in press). However, the early ICI caverns often saw the almost complete removal of salt in a cavern, leaving little or no roof salt protecting the overlying nonsalt beds. These caverns generally collapsed, but as the technique was improved and knowledge of salt mechanics grew, so to did brining techniques. This led to the production of more stable caverns, particularly on abandonment. The technique of the design and solution mining of salt cavities in bedded or domal salt structures for the purpose of high-pressure gas storage is now well advanced. The design and construction of caverns specifically for gas storage is now at such a stage that a process termed solution mining under gas (SMUG) is performed – storage of product begins as creation of the remaining cavity continues (e.g. Chabrelie, et al., 1998 – and section 2.2.7.3.2).

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In England, there are an increasing number of proposals to design and construct salt cavern facilities for the purposes of underground storage of natural gas. Salt cavern facilities generally serve to store smaller volumes of gas than those that can be stored in aquifers or depleted reservoirs, although the larger cavern facilities with 10's of caverns can provide storage volumes approaching those of small oil/gasfields. Importantly, however, salt cavern storage facilities complement large porous reservoir storage, offering several advantages including high deliverability and degree of availability, short filling period and low percentage of cushion gas (which can be almost completely recovered on abandonment of the facility). Thus the combination of the two types of storage, in porous reservoirs, which are generally used to guarantee basic demand to meet seasonal variations, and storage in salt cavities, which are generally operated to cover peak demand, allows high withdrawal rates even at the end of the withdrawal period.

Whilst halite with its extremely low permeability and general viscoplastic deformation is viewed as an ideal storage medium, there are examples of salt having suffered brittle deformation, with the indication that long-range migration of methane has occurred through the fractures (Terrinha et al., 1994; Davison et al., 1996a). This has potentially important implications for not only hydrocarbon potential of basins but also gas storage and is reviewed further in section 6.1.4.

In this report the main incidents at storage facilities that caused injuries or casualties and what were believed to be the factors and causes behind their occurrence are briefly reviewed. One or two examples of salt cavern storage facilities had to close due to volume loss and these are included for completeness. However, it is stressed that these latter incidents were not associated with cavern failure, release of stored material or any loss of life or injury. Furthermore, there are few cases of catastrophic failure (collapses) known and caverns do not, in general, fail catastrophically or close rapidly when depressurized for short periods of time. Most cavities are

held at hydrostatic pressure, but rarely, some may have 'empty' periods when they are held at atmospheric pressures. Examples exist from around the world of depressurized cavities that have remained stable for decades, for example:

- In the 1950s, a lenticular cavern was excavated by solution mining in the Bryan Mound salt dome in Texas, a site of the later Strategic Petroleum Reserve (Serata, 1984; Thoms & Gehle, 2000; Warren, 2006). It was constructed at an average depth of 550 m, with a height of 55 m and unsupported roof span of 366 m. After excavation, it was filled with LPG but subsequently lost wellhead pressure and was abandoned, empty. Thirty years later, measurements indicated that the cavern was remarkably stable, having lost only about 4% of it total volume (Warren, 2006)
- At the CAES storage caverns at McIntosh, Alabama (refer section 2.2.10.2.2), during the replacement of the main operating pipe, the cavern was depressurized for more than six months. There were no roof falls and from subsequent observations it was estimated that the volume of the cavern remained unchanged (Leith, 2001)

2.2.7.1 BS EN 1918-3:1998

Underground gas storage in salt caverns is covered by a British (and European) Standard, which also explains the concept and requirements of developing such a facility (BS EN1918-3:1998; BSI, 1998c). The standard states that salt caverns are generally seen as suitable and preferential sites for the storage of oil and gas, due to the almost zero permeability (to gas) and the viscoplastic nature of salt, which leads to the healing of any cracks and faults. Halite has very high ductility and when subjected to stress, an ability to plastically flow by crystal plastic deformation (creep) processes. This means that it has a low susceptibility to fracturing, but when it occurs, the halite 'anneals' ('flows'), thereby allowing fractures and cracks to seal (see below).

The BS document also provides a series of properties and measurements that are required for the design of caverns:

1. 'mechanical disturbances' for cavities that require determination and include
   - The change in volume loss by creep in the salt formation (convergence)
   - The distribution of the cavity wall and floor deformation
   - The distribution of the stress induced by the cavity in the surrounding rock
2. 'principal stability parameters' that need to be defined within the cavity design and include:
   - The cavity geometry (shape, height, diameter, roof guard)
   - The positioning (e.g. well pattern, depths, pillars, distances to caprock, bedrock)
   - The distance to subsurface neighbouring activities
   - The maximum operating pressure, which shall always be less than the overburden (lithostatic) pressure
   - The minimum operating pressure to prevent closure of the cavern by salt creep

The above calculations and assessments are determined from borehole samples subjected to rigorous laboratory stress and strain tests and/or in situ tests in the well(s). The results of the tests provide the engineering parameters and rheological model of the salt used as the basis for the construction of high-pressure gas storage caverns. The tests and models are designed to demonstrate that the cavity will be mechanically stable and capable of containing gas under the proposed/permitted operating conditions, "using acknowledged geological methods and databases." (BSI, 1998b; p.10). Also required is consideration of the cavern operation and performance under emergency conditions and procedures that will enable safe shut down of the facility.

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Chapter 4 outlines some of the main conditions and characteristics of salt beds and their potential impact on the planning, design, development and construction of gas storage caverns.

2.2.7.2 BACKGROUND

As outlined above, salt for a number of reasons, represents a unique host material for the development of (large) caverns and storage of materials that do not themselves dissolve salt. Large underground salt caverns may be used for storage of liquid (oil, NGL's, and LPG), gaseous hydrocarbons, compressed air (e.g. Crotogino et al., 2001; Leith, 2001; Cheung et al., 2003), or the disposal of (generally solid) waste materials and radioactive waste (e.g. Veil et al., 1998). Some caverns in the USA and Russia have been used for the underground testing of munitions and nuclear weapons (e.g. Thoms & Gehle, 2000; Leith, 2001).

The earlier cavern storage facilities utilised brine caverns created during the extraction of salt for the chemical industry. In Canada, LPG has been stored in solution-mined caverns constructed in bedded salts and salt domes since the late 1940s/early 1950s (Tomasko et al., 1997), whilst LPG was first stored in Texas caverns during the 1950s (Tomasko et al., 1997; Brassow, 2001; Favrez, 2003;). At about this time crude oil was being stored in caverns in England (Brassow, 2001). Storage of natural gas in salt caverns first occurred in 1961, when the Southeastern Michigan Gas Company leased an abandoned salt cavern from the Morton Salt Company near Marysville, Saint-Clair County, Michigan (Allen, 1972; Tomasko et al., 1997). In the Teesside area in the UK, former ICI brine caverns are still in use for storage of a range of hydrocarbon products (refer Table 1).

The first salt cavern specifically designed and constructed for natural gas storage was built by the Saskatchewan Power Corporation at Melville, Saskatchewan, Canada in 1963. This was followed in 1970 by the first purpose built gas storage caverns constructed in the USA, at the Eminence Dome, Mississippi (Thoms & Gehle, 2000). The American Strategic Petroleum reserve (SPR) represents the world's largest stock and supply of emergency crude oil, amounting to around 700 million barrels. The SPR was established in 1977 with a large part of the oil stock stored in huge underground salt caverns along the coastline of the Gulf of Mexico.

In Europe, salt cavern storage of natural gas commenced in Armenia (Abovian, 1964), followed by Germany (Kiel, 1969) and France (Tersanne, 1968). Storage was in caverns whose capacity was limited to between 30,000 - 100,000 m^3, in order to avoid problems that were then known and encountered in salt mines (Chabrelie et al., 1998; Favrez, 2003). Between 1971 and 1978, the German Federal Republic commenced building of its strategic oil reserve, using caverns constructed in the Etzel Salt near Wilemshaven. Some of the original caverns are now converted for use in gas storage. Many countries have large numbers of caverns used for storage purposes, including the Federal Republic of Germany, which in 1982 had about 140 (Jenyon, 1986c). In 1978 the first compressed air storage facility was constructed in the Huntorf salt dome near Hamburg (Thoms & Gehle, 2000; Crotogino et al., 2001).

Hydrocarbon storage in salt caverns now has a long history, particularly in the USA. During the early 1990s there were 648 solution-mined caverns licensed in Texas alone, with around 200 being in bedded salt areas (Seni et al., 1995; Hovorka, 2000). In 2003 over 1000 caverns were in use in the USA for the storage of various products, including waste (Neal & Magorian, 1997; Brassow, 2001; Knott, 2003). Those storing hydrocarbons range in size from 0.4 million to 40 million barrels (circa 0.062 to 6.2 Mcm) and with pressures of up to 800-4000psi. Approximately 50 of these caverns were in use to hold about 200 billion cubic feet (bcf = c. 5.66 Bcm) of natural gas (Knott, 2003). Worldwide, thousands of salt caverns have previously and are currently being used for the storage of hydrocarbon products (Thoms & Gehle, 2000; Bérest et al., 2001; Bérest & Brouard, 2003).

In contrast to the practice of re-using of old brine caverns, present day design and construction of gas storage caverns includes significant geomechanical design work and engineering. This

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ensures the long-term safety and stability of the cavern and associated below ground infrastructure.

2.2.7.3 THE PROCESS

Most modern day salt cavities used for storage of fuel products have been created by the process of solution mining. The solution mining process involves the injection of fresh (or sea) water into the salt body, which dissolves the salt resulting in brine, which is then withdrawn from the emerging cavity and replaced by injecting fresher water. The technique was taken up and pioneered in the UK by ICI during the 1920s and the process recovers up to about 25% of the total salt reserve. Nowadays, it has been recognised that brine caverns have a value after brining operations have ceased and brine caverns are often carefully designed and constructed to be used for gas storage purposes and therefore maintain the stability of the overlying strata and so avoid surface subsidence. Each cavity is developed through a single borehole drilled into the salt beds, which is used to extract the salt and which will then serve for gas injection and withdrawal once the cavity is constructed (Fig 4e). The borehole is drilled using standard oil industry drilling methods (see section 2.2.3). However, the well is initially wider than conventional oil/gas exploration and development wells and the drilling fluid used is brine to prevent dissolution the salt by water-based fluids during drilling. A series of pipes or 'casings' are then cemented into the borehole to provide protection for the surrounding sediments as water is injected and withdrawn during dissolution of the target salt beds (section 2.2.7.3.2).

2.2.7.3.1 Well design, spacing, cavern design and shaping

The detailed design and engineering aspects of well design, spacing and cavern shaping are beyond the scope of this report. For more information on basic solution mining techniques for various salts and the general procedures for controlling the shape of solution mined caverns the reader is referred to Remson et al. (1966), Jacoby (1974), Shock (1985) and API (1994). In the simplest system, the design of a salt solution well comprises two or more columns of steel pipes (casing strings), one inside the other. An initial borehole with a diameter large enough to accommodate the required pipes/tubings is drilled and casing cemented in place to prevent any leakage and contamination of groundwaters during the operations. Near surface the borehole is widest to allow for installation of several concentric layers of pipe casing, which assist the initial drilling of the borehole. The outermost casing (also referred to as surface casing) does not generally extend all the way down to the cavern roof. Instead, a final casing string is cemented in place from some distance above the salt to some way below the top of the target salt to ensure that during dissolution, a set thickness of salt remains in place as a salt roof to the emerging cavern. This process was not generally undertaken during purely salt brining activities, hence the propensity for the removal of all roof salt, which often led to the collapse of cavern roofs and subsidence as seen at, for example, Preesall (NW England – section 8.7.2.1.1 and Fig. 5b). One or more noncemented concentric casing strings (or tubing strings), one inside the other(s), are then placed inside the final casing string, forming one or more annuli. Through one of these strings fresh water (or undersaturated brine) is pumped down the well under carefully controlled conditions to dissolve the target salt beds and create the cavity. The resulting brine is then returned to the surface for processing and recovery via a second tubing string. As the brine is removed, it is replaced by fresher water, dissolving more salt and thereby expanding the cavity. Most modern wells have a third casing string through which an inert protective blanket fluid is injected (normally diesel, nitrogen or compressed air). This floats on top of the brine, providing insulation from the effects of solution, to the roof salt and cemented casing as it enters the cavern. It prevents rapid upward stoping and ultimately, collapse of the cavern roof and well damage. The thickness (or depth) of the blanket fluid is carefully monitored as the cavern is gradually enlarged.

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In the USA, the brine wells are generally laid out on a regular grid with new wells being drilled around 200 m apart. Proposed and actual wellhead spacing in the UK varies, being around 400 m at Atwick and 280 m at Byley (Appendix 7). At the proposed Preesall site, it was planned that a number of deviated wells would be drilled from one site to access and supply a number of caverns from one wellhead platform.

2.2.7.3.1.1 Example of a proposed salt cavern gas storage well casing program at Preesall, NW England

The following summarises the casing program proposed for a typical gas storage well at Preesall (Heitmann, 2005):

- Conductor casing – 22" (559.0 mm) pipe, to circa 15 m overall length
- Surface casing – 18" (457.0 mm) pipe, to circa 110 m overall length
- Production casing – 13 ⅜" (339.7 mm) pipe, to circa 400 m overall length
- Injection tubing string - 10¾" (273.1 mm), to circa 600 m length
- Injection tubing string – 7" (177.8 mm), circa 610 m length

2.2.7.3.2 Salt cavern design and construction

Salt cavern design varies not only due to engineering/construction constraints placed upon it by local ground and geological conditions, but also operational requirements. Caverns will generally be ellipsoidal in shape with long axes vertical. Ultimately, any decision to undertake gas storage in salt caverns constructed in bedded salts will generally require that a number of caverns will be located in a relatively confined area. This is partly to ensure maximum efficiency, but it also contributes to long-term security against breaching of more isolated and disparate caverns caused by future human activity. The spacing of caverns, as well as their optimum shape, are calculated based on careful simulation using in situ and laboratory tests of materials and long-term creep models (e.g. Rothenberg et al., 1999; Dusseault et al., 2001).

Typically, salt domes used for natural gas storage are between 450 m and 2000 m below ground level, although in certain circumstances they can come much closer to the ground surface. Salt beds from which salt domes develop, are usually no more than 300 m – 400 m in thickness and are often interbedded with other evaporitic and insoluble (non salt) horizons (sections 2.2.7.3.4 & 5.3.1).

Construction of 'conventional' large volume solution-mined salt cavities is generally possible in bedded salt layers of 150 m to more than 400 m, but caverns have been constructed in thinner salt layers of 60 m - 100 m, producing cavities with geometric volumes between 50,000 m^3 and 100,000 m^3 (Chabrelie et al., 1998). However, many areas of the world have thin salt layers of less than 60 m thickness and cavern storage projects have been proposed in New York State (USA), with as little as 27 m of bedded salt. At Holbrook, Arizona, short and flat LPG caverns have been constructed in only 34 m of bedded salt at depths of 305 m below ground level (Neal & Magorian, 1997). Gaz de France has investigated the technical and economic conditions in which thinner salt layers can be used for gas storage. Their studies found that tunnel-shaped cavities of 1,000 - 3,000 m^2 cross-sectional area, stretching almost horizontally over several hundred metres and with a volume between 100,000 m^3 and 1,000,000 m^3, are stable (refer Chabrelie et al., 1998).

For caverns at a depth of 1000-1400 m, the convergence rate is usually below 1% per annum (Plaat, in press). With increasing depth, both the temperature and the overburden pressure increase, the consequence being that convergence rates increase rapidly with depth. To illustrate, near Harlingen in the Netherlands in a solution mining operation at depths up to 3000 m, convergence in the order of 70% per year has been observed (Breunese et al., 2003; Plaat, in press). The cavern thus closes almost as quickly as the salt is mined and is presumably associated with significant subsidence problems.

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Conversely, as the pressure at which the gas can be stored increases with depth, it is desirable to create a cavern as deep as possible, maximising the amount of gas that can be stored per cavern. This means that, in general, salt caverns are found at depths ranging from 700 to 1700 m, while the optimal range is usually between 1000-1500 m (Plaat, in press).

Several methods for developing and shaping caverns exist (e.g. Warren, 2006):

- Direct circulation – fresh water is injected through the tubing strings and brine is withdrawn through the annular space between the tubing string and the final (cemented) casing. The pressure differential between the point of entry and the point of exit from the cavern, and the fact that the injected water is lighter than brine, causes convection, which is responsible for the major portion of the dissolution and in this way there is thus a continuous circulation of water (Leith, 2001). This process leads to the formation of more cylindrical caverns
- Reverse circulation – fresh water is injected through the annulus and the brine is withdrawn through the tubing string. This method produces caverns with much wider tops than bases, particularly where no fluid blanket is employed during leaching, as the less dense freshwater floats on top of the more concentrated brine

The resultant brined cavities are typically up to 145 m in diameter and up to 200 m in height, but can be significantly larger in thick salt dome salt. Two of the largest in the USA are about 670 metres in height and 180 metres in diameter, with capacities of over 17,000,000 m^3 (Leith, 2001). The position of the water injection tube and the depth of the protective blanket fluid control the area of salt dissolution. By changing their position during development and by changing the direction of convection, the final size and shape of the cavity can be controlled. The brining operation can be done in a variety of ways (Fig. 4e), from the top down or, most commonly, bottom up, with cavern development monitored by sonar techniques. Insoluble mudstone falls to the bottom of the cavity and collects in what is termed the 'sump'; a volume designed into the cavern to maximise cavern storage space and operational efficiency. Depending on the size of the cavern and the amount of impurities present in the salt (either as dolomite and anhydrite interbeds or more disseminated material throughout the salt body), more than 20 metres of residue can accumulate in the sump at the bottom of the cavern (Crossley, 1998; Warren, 2006)

In the USA, a further method of cavern construction, that of solution mining under gas (SMUG), is developed. This method allows a cavern to be put into gas storage operation sooner (Chabrelie, et al., 1998). Initially the cavern is developed by conventional solution mining techniques. However, its upper section is then developed up to its designed final diameter ahead of the lower section. The design also requires a few modifications of the wellhead and solution-mining strings in order to allow for gas storage in the cavern upper section while continuing solution mining the lower section. The upper section of the cavern is then dewatered as gas is injected and stored whilst the solution mining process is resumed, creating the lower section. Gas stored in the upper section therefore acts as the blanket for continued solution mining of the lower section. The technique also means that existing caverns can be further developed by commencing/resuming SMUG.

2.2.7.3.2.1 Cavern stability and damage - minimum and maximum cavern operating pressures

The structural stability of caverns in bedded or massive salt deposits depends upon many interrelated factors, including local hydrology, geology and rock properties, cavern operating conditions, cavern depth, cavern geometry and cavern location with respect to other caverns (e.g. Pfeifle & Hurtado, 2000; DeVries et al., 2005). Successful cavern design, construction, long-term operation and abandonment must provide conditions for long-term cavern stability in order to maintain the integrity of the salt. To achieve stability and prevent damage to the cavern walls and roof means avoiding conditions known to adversely affect cavern stability and which would

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allow the formation of microcracks and gas permeation in the cavern walls/surroundings (see below and section 4.2).

One of the reasons rock salt is a favoured storage medium is that it is a viscoplastic material that is difficult to fail under moderate levels of confining pressure. Under conditions of triaxial compression, which is often the case for natural underground stress situations, the confining pressure may be sufficient to suppress fracture. In this case, deformation will continue indefinitely without failure. However, the introduction of a cavern within a salt body alters this steady state and results in varying states of stress around the void. The roof rock of a cavern is now in a state of triaxial extension. Rock is typically weaker in triaxial extension than in triaxial compression - salt behaviour is elastic-ductile when short-term compression tests are considered, but is elastic-fragile when tensile tests are considered (Bérest & Brouard, 2003). In the long term salt behaves as a fluid in the sense that it flows even under small deviatoric stresses (section 4.2). It is, therefore, important to understand the creep and strength characteristics of salt under these differing states of stress around the void/cavern.

Under triaxial extensional stresses, the salt body will dilate, which is manifested as a volumetric expansion (increased porosity), resulting from microfracturing of the material (refer Fokker in Bérest & Brouard, 2003; Munson et al., 1999). This process can become severe enough to cause spalling (breakouts) in the cavern roof and/or walls and subsequent damage to the cavern or hanging pipestring(s). Fracture in salt and spalling occurs by the formation and evolution of microfractures. These take the form of "wing tip" cracks (Fig. 6j), either in the body or the boundary of the salt crystal/grain (Munson et al., 1999). Under shear stresses, this type of crack deforms, opening up and producing a volume strain, or dilatency. If there is sufficient confining pressure (e.g. in nature or in a cavern with high enough gas pressure), then fracture formation is suppressed. However, if the confining pressure is too low to suppress fracture initiation and growth, then the fractures will evolve with time to give the characteristic tertiary creep response (Munson et al., 1999). This tertiary creep is a combination of the fracture development and the natural creep and fracture healing processes in salt. Significantly, the volume strain produced by microfractures may lead to changes in the permeability of the salt, which would be of concern in the cavern sealing and operation.

Maintaining structural stability and the integrity of the host salt deposit is therefore achieved by avoiding or limiting microfracturing in the salt. Cavern design must avoid the state of deviatoric stress whereby the difference between the gas pressure inside a cavern and the in situ stress of the surrounding salt becomes too large that dilation of the salt occurs (DeVries et al., 2002, 2005). In a gas storage cavern, the pressure to prevent damaging triaxial extensional stresses within the cavern walls and roof is provided by the brine during construction and gas during storage operations.

On the other hand, as alluded to elsewhere, if the cavern pressure is too high, then fracturing of the salt and surrounding rocks may occur. Hence a maximum operating pressure is calculated, to ensure that storage pressures remain below the vertical component of overpressure.

Munson et al. (1999) take these concepts and model cylindrical caverns and illustrate that stress conditions around the cavern do not lead to large amounts of damage. The damage is such that general failure will not readily occur. Furthermore, the extent of the damage does not suggest possible increased permeation when the surrounding salt is impermeable. Modelling stress distribution around cavities indicates that fracture pressure is also a function of the rate of pressure increase and the creep rate of the salt (Wallner, 1988). For slow pressure build-up rates modelled for sealed caverns, pressures greater than lithostatic can be contained within the cavern without causing fracture. However, at shallow depths and low salt creep rates, fracturing can be induced at very low-pressure change rates (Byrnes, 1997).

An aspect of the calculations on and modelling of cavern stability and internal pressures includes an assessment of the load bearing capacity of the surrounding rock mass in the event of a rapid blowout (depressurisation) of a gas storage cavern down to atmospheric pressure. The purpose of

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this investigation is to prove that a sudden drop in pressure to atmospheric in a cavern does not lead to a chain reaction resulting in the collapse of the cavern and/or of the whole cavern field. These calculations can be done within the scope of theoretical studies of ultimate boundary conditions for a cavern wall failure based upon the knowledge of salt mechanics and specific laboratory tests.

As would be expected, many studies have been undertaken into the design of new salt caverns and the potential extension of the useful life of older salt caverns by a greater understanding of the manner in which older caverns and sealing systems might fail (see e.g. Chan et al., 1998; Lux et al., 1998; Munson et al., 1999). These studies have looked at the damage zone around older caverns and on the creep, microfracture development and healing processes in the salt body. In particular, micromechanical mechanisms of fracture and the concept of a fracture mechanism map have been developed and refined. This knowledge feeds into modern cavern design calculations.

2.2.7.3.2.2 Leaching rates and brine disposal

Leaching rates and thus construction times vary with the amount and degree of salinity of the water injected. It is common to find that for every seven cubic meters of fresh water injected, a volume of one m^3 is leached (Leith, 2001). Leaching rates are normally expressed as the amount of water or brine circulated and can reach rates of 1600 m^3 per day. In the U.S., leaching rates of 320,000 m^3 to 400,000 m^3 per year are common (Leith, 2001). Construction rates for the two 150,000 m^3 solution-mined caverns at Huntorf in Germany were an average of about 360 m^3 of salt per day, at a maximum circulation of 600 m^3 per hour. Each cavern was completed in about 14 months and it took a further five months to remove the brine from each of the caverns (Leith, 2001).

Brine displaced from a leached cavern is normally first pumped into a surface holding tank to allow any insoluble residues that did not settle in the cavern but were carried out by the brine, to settle out. Disposal is by either injection into subsurface saline aquifer close to the development, or by pumping out to sea. In the USA, water is also injected into vugs (natural solution cavities found in the cap rock to salt domes at relatively shallow depths), a technique not available onshore the UK.

In the UK, the brine might be used as a chemical feedstock. For example, in the Cheshire Basin area, Ineos Chlor produces brine during the construction of caverns at Holford that is pumped 3 km to a purification plant at Lostock. It is then pumped to consumer plants at Brunner Mond's two soda ash plants in Northwich, as well as Salt Union's vacuum salt plant and Ineos Chlor's own chlor-alkali plant, both near Runcorn.

However, during the investigations at Preesall, no immediate or nearby market was found for the brine and it is proposed that the brine will be discharged into the East Irish Sea through a pipeline to be constructed for the purpose. Similarly, it is proposed to discharge the brine from the Portland solution mining activities out at sea.

2.2.7.3.3 Subsidence occurring with cavern formation and overburden/caprock stability

It is a well-known fact that natural solution of concealed salt beds by circulating groundwaters leads to subsidence of the land surface. In addition, subsidence and impacts on hydrologeological regimes occur at many underground mining operations, causing changes to surface landforms, ground water and surface water flow. All solution-mined caverns converge as they very gradually shrink due to salt creep (Bérest & Brouard, 2003). This occurs until either the salt to fill the void or confining pressures and cavern pressures are equalised and is associated with varying degrees of subsidence. The impacts of mining and solution mining operations to man-made surface structures and other features are relatively well known and studied and are outlined further in section 8.7. Subsidence may be accelerated if total salt extraction has been allowed to

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occur (leaving no roof salt in the cavern). This could cause collapse of a salt cavern or mine, which can in turn lead to catastrophic failure and collapse of the overburden, resulting in the formation of a (often deep) crater at surface. Such events have occurred in salt workings in Europe and in the UK at the Preesall brinefield (Lancashire – refer Wilson & Evans, 1990; Jackson, 2005 – section 8.7.2.1.1 and Fig. 5b).

2.2.7.3.4 Insoluble (non salt) interbeds

The presence and understanding of the physical and mechanical properties of non-salt interbeds are important for at least two reasons:

- Their presence could mean that salt caverns in bedded salt may be more prone to deterioration, may develop less than ideal and unstable shapes and may therefore be more expensive to develop than caverns in the more massive salts of salt domes
- Experience elsewhere has shown that the weakest point in the salt deposit are the salt/shale layer interfaces and these interfaces are where fractures may initiate and then propagate, generally in a horizontal plane (KDHE, 1997). This may become an issue if rock mechanical tests are not undertaken on such interfaces to deteremine strengths and failure pressures and/or cavern pressures are not monitored and kept below the fracture strength of the two rocks and their interface (see the account of the Hutchinson incident in Appendix 5).

In the UK, halite beds include interbedded non-halite beds (mudstones, dolomite and anhydrite beds – section 5.3.1), which are generally thin and distributed vertically throughout the salt body, such that halite forms 90-95% of the evaporite sequence, as seen at Byley and Preesall (e.g. Beutal, 2002; Evans et al., 2005). At Byley, the experience of Ineos Chlor (formerly ICI) is that the solution mining of halite sequences with marls over a metre in thickness presents no operational or safety problems, as the insoluble marls become soft, crumble and fall down to the base of the cavern during solution mining (Beutal, 2002).

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2.2.7.3.5 Summary and examples of proposed UK cavern design and operational ranges

To summarise, therefore, during the design of a salt cavern gas storage facility a number of fundamental in situ and laboratory tests are required to ascertain the suitability of the halite beds and determine the size, shape and spacing of caverns. These include:

- Core study and testing to determine the purity of the salt and nature of interbed material
- Core testing to determine strength and creep of the salt and determine the essential material parameters for rock mechanical calculations
- Distance both horizontally and vertically to the nearest fault
- Distance both horizontally and vertically to the nearest non salt formation and establishing its nature
- Numerical modelling and simulation based upon the rock mechanical data

Numerical modelling based upon carefully acquired field and laboratory data on the rock mechanics, depth and thickness of salt is undertaken to design cavern shapes and spacing. The numerical simulation covers the anticipated loading history during cavern operation that includes the effects of cyclical pressurisation and extended periods at maximum pressure (to prove gas tightness of the cavern).

From these simulations and measured rock properties recommendations on the following are given regarding the design of a gas storage cavern in any particular area:

- minimum thickness of the salt layer above the roof
- depth of the cavern
- geometrical shape – has to be consistent, as irregular shapes could lead to areas of differing stress causing spalling (microfracturing) or breakouts of the cavern walls
- minimum and maximum operating pressures to maintain cavern stability and minimise closure due to salt creep – including the allowable time period during which the cavern can be operated at the minimum pressure
- minimum pillar dimensions with respect to adjacent caverns or to the boundary of the salt rock formation or faults and pillar stability
- Loss of volume due to cavern wall convergence during operation

As examples of cavern design and specifications for proposed UK developments, information presented during the Public Inquiries into the proposals to develop salt cavern storage facilities at Byley, Cheshire (2002) and Preesall, Lancashire (2005) is summarised below:

(a) Byley caverns at depths of circa 630 m were (Crotogino, 2002):

- Maximum cavern radius = circa 45 m (90 m diameter)
- Maximum cavern height = circa 100 m
- Thickness of remaining salt above cavern = 170 m
- Distance between deepest point of cavern and underlying formation = >10 m
- Spacing between wellheads – 280 m
- Between adjacent caverns, pillar width/distance = 196 m (minimum)
- Minimum cavern pressure – 38 bar (35 bar is minimum operating pressure for rock mechanical design of cavern)
- Maximum cavern pressure – 105 bar (rock mechanical design), 110 bar is design basis for maximum operating pressure of surface equipment

(b) Preesall caverns with tops at depths of between 220 and 425 m were (Rokahr, 2005):

- Maximum cavern radius = circa 50 m (100 m diameter)
- Thickness of remaining salt above cavern = > max radius of the cavern = > 50 m
- Distance between deepest point of cavern and underlying formation = minimum of 20% of max radius of cavern
- Spacing between wellheads – not specified, wellheads will form the base for a series of directionally drilled wells to different cavern locations
- Between adjacent caverns, minimum pillar width = 3 times maximum cavern radius. At substantially greater depths (> 800m) this would be 5 times the maximum cavern radius
- Distance of cavern from significant nearby fault(s) = 3 times maximum cavern radius.
- Minimum cavern pressure – to be above 30% of the vertical component of overburden pressure
- Maximum cavern pressure – to be below 83% of the vertical component of overburden pressure

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2.2.7.4 Commissioning of caverns – pressure testing

Tightness is a fundamental prerequisite for many underground works where minimum product leakage is required (Bérest & Brouard, 2003). This is both for safety, environmental (groundwater pollution etc.) and economic reasons – the latter can depend on the speed of stored product rotation, but the first two require greater consideration. Therefore, once the caverns are 'brined' out to their desired size and shape and before they can be commissioned for underground storage, a Mechanical Integrity Test (MIT) is used to test cavern (and well) tightness. The first stage involves pressure testing of the wells and the cements/casings to verify there is no leakage behind the casing. A sonar survey is also generally performed.

After the pressure testing of the well is complete, the MIT is performed pressuring the cavern up to operational pressures, shutting in and monitoring the pressure changes over a specified period. The pressuring up may be done cyclically in some tests. Two main types of MIT are currently used (Bérest et al., 2001):

- The Nitrogen Leak Test (NLT) – consists of lowering a nitrogen column in the annular space below the last cemented casing. The NLT is generally used for full size cavern testing. The central string is filled with brine and a logging tool is used to measure the brine/nitrogen interface level. Two or three measurements, separated by a specified period of time (usually 24 hours), are usually performed. The levels of the nitrogen are then compared. An upward movement of the interface is indicative of a nitrogen leak. Pressures are measured at ground level and temperature logs are performed to allow precise calculation of nitrogen seepage
- The Fuel Oil Leak Test (FLT) – a more popular test in Europe than in America and generally used before the cavern is leached out, testing the wellbore tightness. The FLT consists of lowering a fuel oil (instead of Nitrogen as above) column in the annular space. During the test, the evolution of the brine and fuel oil pressures at the wellhead is continuously monitored. Severe pressure-drop rates are indicative of poor tightness. Following the test, the fuel oil is withdrawn and weighed permitting comparison with the weight of the injected fuel oil volume.

Care must be exercised when performing a tightness test however: at the beginning, cavern pressure is built up rapidly and short-term transient creep (refer section 2.2.7.3.2.1) must be taken into account. If neglected, it can lead to serious misinterpretation of the test results (Hugout, 1988; Bérest et al. 2001; Bérest & Brouard, 2003). Transient creep and the duration of each pressure step must be taken into account when natural gas caverns are operated at varying pressures. Additionally, rock damage and coupled hydromechanical behaviour must be considered both when the cavity pressure is very low (Cosenza & Ghoreychi, 1996; Pfeifle et al., 1998; Pfeifle & Hurtado, 2000) or close to geostatic pressure – particularly important on cavern abandonment (Bérest & Brouard, 2003). Much is written on the tightness testing of storage wells and caverns and the reader is referred to Bérest et al. (2001) and Bérest & Brouard (2003) for further discussion on and comparison of the uses of both the NLT and FLT tests.

2.2.7.5 The stored products and cavern operation

Mention should be made of how the materials (liquids, liquefied hydrocarbons [LPG, ethylene and propylene], natural gas and compressed air) are stored and retrieved, the pressure distributions that exist in the caverns and the consequences of well failure. A fuller account is given in Bérest and Brouard (2003).

The stored product is retrieved in a variety of ways from cavern storage, depending on the product. If the products are liquid (crude oil, LPG etc), then the cavern is generally operated in what is termed 'brine-compensated mode'. This involves injection/withdrawal of an equal volume of brine as product is removed/replaced and requires that large holding tanks or ponds of brine are available during periods when the caverns are full. The products are held under

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pressure by the weight of brine in the tube, which has a higher density than that of oil or LPG. Oil or LPG in the annular space (between the tubing and well casing) is thus under pressure. Failure of the wellhead valve would result in the sudden release of the pressurised product held in the annular space. In the case of oil this would not be as great as LPG, which would, on the release of the pressure, move up and spill out, evaporating rapidly to form a dense low lying cloud.

It is noted that the Isle of Portland gas storage scheme would appear to be proposing operation of caverns in brine compensated mode (Egdon, 2007a). On a purely cautionary note, brine compensated operation requires careful monitoring of the brine injected. This is because the process can lead to further leaching of the cavern that has occurred unnoticed and has led to problems at some facilities (section 9.3 and Appendix 5).

Natural gas caverns may be operated in this way, but they generally rely upon the pressure of the stored gas for 'lift' during withdrawal phases. During the storage of natural gas, pressure builds up as the gas is injected and falls as it is withdrawn. If casing or wellhead failure occurs, then left unchecked, virtually the entire working gas volume of the (full) cavern would be expelled. The time frame for this release is dependent upon the initial gas pressure and the leakage rate. Sudden failure of the wellhead could result in rapid and catastrophic depressurisation of the cavern and release of gas. A consequence of this would be severe stressing of the cavern walls, leading to collapse in some cases. These wellhead risks are normally addressed in modern design by inclusion of fail-safe valves below the wellhead.

2.2.7.6 Asymptotic pressurization of a cavern – post abandonment

Asymptotic pressurization of a cavern relates more to when storage operations have ceased and the cavern has been abandoned following operations (e.g. Dusseault et al., 2001). The gradual closure of large caverns due to creep of the salt can lead to substantial flexure and high strains in the overburden strata, which in turn can substantially increase their permeability. Filling the cavern to a pressure just below that of lithostatic pressure before the cavern is sealed and abandoned is a means of restricting excessive strains, perhaps indefinitely. This requires that the cavern and access well(s) do not leak, which is not always the case and should this occur, brings with it problems that require previous planning (see section 2.2.7.6.1). Thus post-gas storage cavern decommissioning/abandonment/mitigation planning strategies are worthy of note at this stage.

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Five possible reasons for long-term pressure changes in a cavern exist and require modelling/consideration (Bérest et al., 2000):

a) Salt creep. This may be the dominant process, however, analysis of creep effects alone shows that cavern pressure approaches that of the lithostatic only asymptotically if creep is the only process (i.e. no leakage). Over pressuring and possible hydraulic fracturing as a result is a possibility, but is thought unlikely.

b) Thermal expansion of the cavern fluid. The slow heating of brine in a salt cavern could have a much more important effect on the increase in cavern pressure than creep itself.

c) Transport of the fluid out of the cavern into surrounding porous strata via porous nonsalt interbeds. This is likely to have been researched during studies of gas tightness for the operational phase.

d) Leakage along the well path is a very real process as identified elsewhere in this report. Bérest et al. (2000) point out that, as pressures asymptotically approach lithostatic, local pressure gradients may become quite large.

e) Additional dissolution and precipitation of the salt in the cavern (e.g., driven by temperature differences [thermal gradients] and slow convective currents in a cavern). In a brine-filled cavern of great vertical extent (e.g. up to 600 m high in the American Strategic Petroleum Reserve in

domal salts), slow downward growth can take place because salt solubility is fractionally higher at the base; the thermal gradients generate slow convection currents causing salt deposition at the top of the cavern. However, the effects and potential problems might be less in a bedded salt deposit where the brine is saturated and the vertical cavern extent is perhaps only 50-100 m, with only a very small temperature difference likely across the cavern height (Dusseault et al., 2001).

2.2.7.6.1 High pressure brine release, Preesall Brinefield, Fylde, Lancashire

The following incident is of note in the fact it appears to represent a documented case of salt flowage and asymptotic pressure development in an abandoned former ICI brine cavern. On abandonment of the cavern, brine was injected immediately prior to sealing in order to maintain cavern pressure and aid stability. The brine well and cavern was later the site of a (high-pressure) release of brine (Fig. 5a).

The incident occurred in 1994 and relates to a brine gusher at ICI brine well BW 124, drilled in 1985. A local resident first observed the gusher as he turned onto Highgate Lane from Staynall Lane crossroads, approximately 1.75 kms from BW 124. From there, the top of the plume of brine could be seen over the intervening hill and on closer approach, the 'noise was deafening'. The eyewitness account continues 'the drift from the plume of brine reached as far as Corcas Farm, about 650 m away, in the direction of Preesall, the salt was visible on the grass days after, trees were white with it' (Jackson, 2005).

Clearly, although it is assumed that no existing brine caverns or associated pipes and well heads would be used in developing a new UGS facility in caverns, the image shows a potential problem posed by the existing brine pipework and caverns. Whilst the well was drilled in 1985, the date of cavern abandonment and well capping is not clear. However, brine extraction operations in the saltfield ceased in 1993 because of the closure of the chlorine plant at Hillhouse in Thornton Cleveleys (Evans et al., 2005; BGS, 2006a). It therefore illustrates the extent of pressure build up in the cavern in the interval to 1994 when the pressure was released by the expulsion of the brine that was left in to stabilize the cavern.

D2-253 (Cont.)

2.2.8 Other underground fuel storage scenarios

UFS is possible in a number of other geological settings, but as will be seen in later sections of the report, has in some cases been associated with problems of containment of the stored product, due to the fact that host or cap rocks (at e.g. abandoned mine facilities) have not proved gas tight. The types of facility include a number of abandoned room and pillar mines.

2.2.8.1 Abandoned/reconditioned coalmines

Abandoned/reconditioned coalmines offer the potential for the development of natural gas or compressed air storage facilities. They are, however, rare with the Leyden coalmines, located in Jefferson County, Denver, Colorado (Fig. 4f) and abandoned coalmines in the Anderlues and Péronnes mines in the Hainaut coalfield of southern Belgium (Piessons & Dusar, 2003), being examples of such sites. The Beringen mine in the northern Campine coal basin, northern Belgium is also being investigated for the storage of CO_2 (Piessons & Dusar, 2003; Shi & Durucan, 2005). Leakage from such facilities is reported (refer Appendix 5).

2.2.8.2 Abandoned salt mines

Abandoned salt mines have been used quite widely to store fuel products, particularly LPG in America (e.g. Weeks Island, Louisiana), but have included the Burggraf Bensdorf mine in the former DDR in 1970 (Plaat, in press). They are based upon the same principals as abandoned coalmine storage, but are, however, generally at shallow depths and have encountered problems

in retaining the product, being associated with leaks and the escape of stored product (refer Appendix 5).

2.2.8.3 Abandoned limestone mines

Abandoned limestone mines have been converted for gas storage purposes, with the first thought to have been near Lawrenceburg, Indiana, in 1952 (Plaat, in press). Related to gas storage, in 2001, Ohio Power Siting Board approved an application by Norton Energy Storage to develop a Compressed Air Energy Storage (CAES) plant in an old limestone mine 670 m below ground at Norton, about 56 km (35 miles) south of Cleveland, Ohio (Norton Energy, 2001; Sandia, 2001; section 2.2.10.2.3).

A recent proposal has been to create caverns for gas storage in limestone formations through dissolution by acid in a similar way in which salt caverns are created using solution mining techniques (Castle et al., 2004; Plaat, in press). The process is still at the research stage with many factors that require further investigation. These include the issues of gas tightness of the caverns, cavern stability and the disposal of large amounts of CO_2 that will be generated by the dissolution of the limestone. Whilst unlikely to be of immediate interest to developers in the UK, it could potetntially have applications in e.g. the Chalk in which mined caverns are already in operation to store LPG (section 2.2.8.4.3).

2.2.8.4 Rock Cavities other than salt and previous mine operations

Although many specifically mined LPG (or other hydrocarbons) cavern storage facilities exist in for example the USA, Scandinavia and France, the technology has rarely been used in the UK outside of salt caverns in Cheshire and Teesside noted above. Facitities are not, however, unknown with the Killingholme LPG storage facility, constructed in chalk in North Lincolnshire believed to represent the first and still the only mined void LPG storage facility outside the salt beds in the UK (Trotter et al., 1985; section 2.2.8.4.3).

Although there is a lack of such facilities in the UK, the technology has been deployed and could be revisited and thus requires brief summary here. Rock cavities specifically engineered for gas storage may be of two types and are briefly described below.

2.2.8.4.1 Lined rock cavities (LRC)

Lined rock cavities (LRC) provide modest storage capacities in countries where crystalline and metamorphic strata form the majority of rocks at outcrop. LRC's are generally large voids excavated out of the country rock with steel plate linings constructed inside the void to ensure gas tightness. This steel 'vessel' is then cemented in place, with the cement providing a further barrier to gas migration and also infilling the gap between the steel vessel and the rock walls to provide stability and protect the steel plate from damage against the host rock. LRC's thus represent an expensive option but in countries lacking deep sedimentary basins with suitable reservoir and caprock sequences, may offer the only option as an economical means of meeting peak demand.

Examples of LRC facilities and investigations include demonstration plants built at Grängesberg (1988) and at Skallen (construction and evaluation 1999-2002) in Sweden (Vasquez & Tengborg, 2001). In 2004, construction commenced of a further complex of 4 LRC's in Sweden, commenced in granite at a depth of 100 to 200 m, each with a volume of 40,000 m^3 and lined with steel plating (Plaat, in press).

2.2.8.4.2 Unlined rock cavities

Unlined rock caverns have been used for decades to store a wide range of low vapour pressure products, mostly liquids such as crude oil, butane, and propane and it is this type of storage

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facility represented at the Killingholme site (section 2.2.8.4.3). The storage technique was first tested in Texas in 1950 with the construction of an LPG storage facility in a shale formation (Lindblom, 1989). The first such storage facility in Europe was completed in France in 1966 and was followed two years later by the first operational LPG facility in Sweden (near Gothenburg). Since then and into the mid 1990s, around 70 mined LPG storage facilities were commissioned in the USA, with around 20 in Europe, mostly in Scandinavia (Lindblom, 1989a&b; Liang & Lindblom, 1994). The usual stored product is LPG, with few operational unlined cavern facilities storing natural gas. However, an air cushion surge chamber facility in Norway has provided important data on high-pressure storage in unlined rock caverns. The latter facility operated at 7.7 MPa (1117 psi) and all chambers operated satisfactorily and with only minor 'gas' loss (Liang & Lindblom, 1994). The principles of this method should also assist understanding of the storage of gas in other underground storage facilities and the important relationship of hydrostatic water pressures to gas containment and movement away from any injection site and within the rock unit(s).

The most widely used technique for the containment of LPG and natural gas in unlined caverns involves the excavation and construction of a storage cavern at a suitable depth below the groundwater table. Product confinement within the storage cavern is then achieved through groundwater control, either by normal hydrostatic pressure, or what is termed a water curtain (Fig. 7). The concept is to have water continuously flowing toward the cavern from outside and in all directions. The storage facility operates on the principle that hydrostatic water pressures are higher around the cavern(s) than in the cavern. Such storage facilities therefore require that the surrounding rock mass remains saturated with groundwater and the caverns generally have circled-arched (vaulted) roofs and vertical walls, which are reinforced by rock bolts.

Therefore, the cavern must be sited deep enough to ensure that the hydraulic pressure in the pores and fractures of the rock around the cavern is always higher than the vapour pressure of the product stored in the cavern. In this way, the static head (or hydrostatic pressure) of the ground water is greater than the pressure exerted by the stored product. This ensures that the liquid (LPG) or gas is contained in the caverns and prevents outward migration of the stored product out of the cavern and into the rock volume and also allows for groundwater seepage into the cavern (e.g. Åberg, 1977, 1989; Goodall, 1986; Goodall et al., 1988; Liang & Lindblom, 1995; Yamamoto & Pruess, 2004).

A water curtain represents an effective way of increasing hydrostatic pressure and preventing gas leakage from underground storage facilities. It consists of an array of boreholes, drilled over the storage cavern, which are then used to inject water to the surrounding rock and maintain a controlled water pressure (Liang & Lindblom, 1995; Yamamoto & Pruess, 2004). There may be roof water curtains or roof and wall water curtains, the latter contributing to maintaining lateral pressures. Important considerations are the proposed depths of caverns (not only to develop sufficient hydrostatic pressure for containment of high pressure LPG but also to ensure that hydraulic fracturing due to any high pressure water curtain does not occur), cavern size, cavern spacing and water curtain layout. All can have dramatic effects on the maximum storage pressures and thus gas storage capacities of facilities (see Liang & Lindblom, 1994). The cavern bottom is usually saturated with water (a so called water bed) as shown in Figure 7. Further background to and discussion of unlined rock cavity storage can be found in Appendix 8. Examples are also described where fault zones and leakage pathways exist and have been sealed to provide tightness.

2.2.8.4.3 UK Mined (Unlined) Cavern Storage – Killingholme, North Lincolnshire

As noted above, propane and butane LPG are stored in operational underground storage facilities utilising mined and unlined cavities in the Chalk at South Killingholme on the River Humber, North Lincolnshire. The storage facility, some 3 km north of Immingham (Fig. 8: Trotter et al., 1985; Geol Soc., 1985, was opened in 1985 and is jointly operated by ConocoPhillips and Calor

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Gas Ltd. The facility comprises two large underground 'caverns' both having been designed to ensure that peak winter demand for LPG can be met (ConocoPhillips, 2004). Development of the scheme required close co-operation with the Health and Safety Executive and the local (Anglian) Water Authority in whose aquifer the storage caverns are constructed. The scheme was seen to represent the safest method for storage of large volumes of LPG, on two accounts: firstly the stored product is 'safely out of the way, deep underground' and secondly 'the final surface area occupied is very small and compact' (Trotter et al., 1985).

The caverns are 180-190 m below ground level near the base of the Upper Cretaceous chalk and comprise a series of nine storage galleries, each of which is 10 m wide and 10 m high, with a cross-section of 85 m^2. They are constructed in the lower part of the Welton chalk with the sumps extending down into the top of the Ferriby chalk (Fig. 8). The design and their position within the local stratigraphic succession is illustrated in the sketch section through the site (Fig. 8). Access to the caverns was by two 2 m diameter drilled shafts, and the total excavation in each of the two facilities is 120,000 m^3, each capable of storing up to 60,000 tonnes of LPG (ConocoPhillips, 2004). The galleries were excavated in two stages: first a top heading was excavated partly by road header and partly by blasting followed by a bench excavated by blasting.

The chalk was deposited in what is known as the 'Northern Province' and relative to the Chalk of southern England (commonly referred to as having been deposited in the 'Southern Province') has three to four times the strength (Geol Soc., 1985). At cavern level the chalk is massive and undisturbed and dips at 1-2° to the northeast. Sub-vertical joints in the chalk, with a maximum displacement of about 300 mm, are present at a spacing of several metres. The galleries require no rock support, except on a minor scale at gallery intersections. Convergence has been less than 5 mm on the 10 m gallery cross section.

The principle rock characteristics of the Welton chalk are: rock density of 2.2 to 2.3 T/m^3; an unconfined compressive strength of 30-60 MPa; permeability ranging from more that 200 milli-Darcys (mD) in upper parts of the Burnham chalk to less than 10 mD at cavern level (Geol Soc., 1985).

The principle of containment of LPG in the unlined Chalk caverns requires the groundwater pressure in the chalk surrounding the cavern to exceed (by a safety margin) the maximum vapour pressure of propane - some 12 bars (or 1,200 kN/m^2). At Killingholme, the depth of the caverns is almost twice that required to balance the pressure of propane (ConocoPhillips, 2004). The successful operation and maintenance of pressure requires an adequate supply of water from aquifers above and below the cavern to prevent desaturation of the chalk by seepage into the cavern and ensure a seepage rate into the cavern sufficient to guarantee containment. Artificial recharge from a water gallery above the cavern is not necessary. The seepage rate is calculated to be less than 1 m^3/h (Geol Soc., 1985).

2.2.9 LNG storage – potential future developments

Liquefied Natural Gas (LNG) is natural gas in its liquid form cooled to about minus 259 °F (-162 °C). It is generally handled at slightly above atmospheric pressure, requiring the very low temperature. Natural gas is primarily methane, with low concentrations of other hydrocarbons (ethane, propane and other liquefied petroleum gases).

Salt caverns have been used to store Liquefied Petroleum Gas (LPG) for a long time and many attempts have been made to store LNG in underground storage facilities, often involving buried tanks, but with very limited success (Favrez, 2003). Numerous failures have occurred due to thermal stresses generating cracks in the host rock/soils leading to gas leaks and to unacceptably high heat flux rates between the LNG and the ground. These facilities have been decommissioned due to their excessive boil-off rate.

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However, new R&D programs are underway in order to solve previous problems, with a pilot testing plant under construction at Daejong in South Korea during the early 2000s (Favrez, 2003). The concept of this facility is very similar to Lined Rock Cavern (LRC) UGS, but it will contain LNG. Containment of LNG will be based upon the LNG freezing the surrounding rock, forming an impervious ring of ice to a distance that will ensure LNG containment and absorb the hydrostatic loads whilst providing protection of the rock against thermal shock. Initially water is pumped out of the cavern area to assist in the freezing process and prevent hydrostatic pressure acting against the containment system. LNG in these types of storage will be injected and withdrawn using pipes.

One pilot study (founded by US Department of Energy and private companies) is to develop the concept of salt caverns used as off-loading tanks in LNG re-gasification plants (often referred to as the "Bishop Process"). Initially conceived to receive and offload LNG tankers offshore, the underground part is the classical salt cavern, with the main new development being in the re-gasification process. Using seawater as the heat source, LNG will be vapourised (regassified) at high rates to inject into underground storage. The principle consists of a pipe-in-pipe heat exchanger, which has to deal with the ranges of temperature involved (from -160°C to 20/30°C).

2.2.10 Examples of storage of different types of energy in salt caverns and other geological environments

As alluded to above, salt cavern storage can potentially play a significant role in the underground storage of natural gas, liquid hydrocarbons and hydrogen. Storage in other geological settings also plays a role, which might be expected to increase with time. Other forms of energy storage are under consideration, for example compressed air storage.

The following sections briefly review underground energy storage scenarios with regard to potential in the UK in particular and are illustrated by examples of operational facilities from around the world and where possible the UK.

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2.2.10.1 Hydrogen and Nitrogen storage

Hydrogen is a gas at ambient temperatures and pressures, but it can be stored as a gas, a liquid or a solid. In the case of hydrogen, underground (geological) storage provides the greatest volumes and is considered in this report. Solid storage, whereby hydrogen exists as a chemical compound is not considered here.

Compressed gaseous hydrogen represents a mature technology, whereby stationary storage above ground is common, being best suited for frequent turnover. However, underground geological storage provides greater volumes and potentially represents the cheapest option for longer-term storage.

At least two former ICI salt brine cavities are used by BOC Nitrogen for the storage of nitrogen at Wilton in Teesside (refer Table 1). The caverns are in Permian salts at a depth of approximately 650 m.

2.2.10.1.1 Tees Valley Hydrogen Project and renewable energies

The Tees Valley Hydrogen Project near Middlesborough in the north east of England was established to assist in bringing new energy technologies from development to operation within an urban environment. The project capitalises on some of the assets created over the years in the area by, in the main by ICI. To this extent, a 30 km hydrogen distribution system incorporates an underground hydrogen storage facility utilising up to three former ICI salt brine caverns in bedded Permian salt deposits. For over 25 years, the caverns have been used to store up to 1,000 tonnes of hydrogen for industrial use (Padró & Putsche, 1999; BGS, 2006a; Beutal and Black, 2005).

2.2.10.2 COMPRESSED AIR ENERGY STORAGE (CAES)

The technological concept of CAES is more than 30 years old (e.g. Glendenning, 1981), with the first CAES facility commissioned in Germany in 1978, using caverns created in the Huntorf salt dome near Hamburg for storage (Glendenning, 1981; Thoms and Gehle, 2000). Hydroelectric power plants have, for many years, been used to store excess off peak (night-time and weekends) power and provide increased peak time output. CAES facilities likewise provide the potential to store energy and could be used alongside, for example, wind turbines. Though instances of this technology are not numerous, it is likely that compressed air energy storage will assume a greater importance as energy markets change with time. There are proposals that if widespread renewable energy is to become reality, then the utility industry might have to consider more options of energy storage including compressed air (Schaber et al., 2004). This might be facilitated by distributed generation and microgrids in which small CAES plants play an important role storing energy close to the source.

The basic concept is that during the storage phase, electrical energy (from e.g. wind energy or excess output of power plants) is used to compress air, which is stored under pressure (typically around 75 bar) in an airtight underground storage cavern (salt or rock caverns or LRC's). However, storage can also be in porous rocks (aquifers or depleted oil/gasfields). Storage volumes required to make CAES plants economic are large hence above ground facilities are not practicable due to prohibitive costs. When required, the compressed air stored is fed either into an expansion turbine, or mixed with gas, generating power through a generator.

The main disadvantage of CAES is the identification and location of suitable geological structures or sequences close to the generation site. Technical issues surround the heat generated during compression of air, but these are lessening.

Research into CAES is ongoing around the world, with plans to construct a number of CAES plants that will utilise aquifers and former mines. Italy has operated a small 25 MW CAES research facility based on aquifer storage, whilst Israel has conducted research into building a 3x100 MW CAES facility using hard rock aquifers (Cheung et al., 2003).

The following sections outline briefly the existing or planned facilities.

2.2.10.2.1 Huntorf, Germany

The Huntorf plant, situated in north Germany, was developed in 1978 as the world's first CAES plant, using two 150 m high salt caverns (referred to as NK1 and NK2). The caverns are constructed in the Huntorf salt dome at depths between 650 m and 800m (Crotogino et al., 2001; Cheung et al., 2003). Their maximum diameters are 60 m, with the wells spaced at 220 m. The depths permit operating pressures between 43 and 70 bar (4.3 and 7 MPa/624 and 1015 psi), although in exceptional circumstances, minimum operational of 20 bar (2 MPa/290 psi) are possible.

The Huntorf plant has run reliably on a daily cycle for over 27 years, having now completed well over 7000 starts that involve charging over an eight-hour period, then delivering 300 megawatts for 2 hours of discharge (Crotogino et al., 2001; Cheung et al., 2003).

2.2.10.2.2 McIntosh, Alabama, USA

The McIntosh facility is the first CAES plant in the USA and is constructed in the McIntosh salt dome, Alabama (Leith, 2001). Alabama Electric Cooperative's (AEC's) generating units at McIntosh, Alabama, include the compressed air energy storage (CAES) unit and twin gas-fired combustion turbines.

The CAES unit (designated McIntosh unit 1), was declared commercial on May 31st 1991 and officially fully operational on September 27th 1991. In the generation process, the 100-megawatt CAES unit uses air compressed and stored in a 0.57 Mcm (20,000,000 ft^3) underground cavern.

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When the compressed air is needed for generation, it is mixed with natural gas in a conventional gas turbine combustion process to generate electricity. The plant uses off-peak electricity to pump air into the cavern and then uses the stored air in the generation process during peak periods. One full charge from the 110 MW CAES plant provides enough electricity to supply the demands of 11,000 homes for 26 hours (http://www.caes.net/mcintosh.html).

In June 1998, contractors completed work on two single-cycle combustion turbines at the McIntosh site. The units have a generation capacity of 226 megawatts, and are designed as McIntosh units 2 and 3. While these units are not CAES units, they have increased the total power generation capacity of the McIntosh facility to over 326 megawatts.

The top of the 275 m high solution-mined salt cavern is at 457 m (1,500 ft) below ground level, with the bottom of cavern at 732 m (2,400 ft). The cavern is circa 76 m in diameter and provides approximately 315,000 m^3 (19 million ft^3) air storage (Leith, 2001). At full charge, air pressure is 76 bar (7.6 MPa/1,100 psi), whilst at full discharge, cavern air pressure is 45 bar (4.5 MPa/653 psi).

2.2.10.2.3 Norton, Ohio

In 2001, Ohio Power Siting Board approved the Norton Energy Storage (a subsidiary of CAES Development Company [CDC], a Houston based energy company) application for a certificate of environmental compatibility and public need to develop a CAES plant in an old limestone mine 670 m below ground (http://www.caes.net/nortpres.html). This development is located on a brownfield site within the city limits of Norton, about 35 miles south of Cleveland, Ohio.

Commercial operation was estimated to begin in 2003 and to be fully operational by 2008. The development plan involves the installation of nine 300 MW Alstom ET11NM turbines, capable of ultimately producing 2,700 MW of electricity, serving over 675,000 homes. When fully operational, it is claimed that the plant will only produce the same amount of emissions as a 600-megawatt gas-powered combustion turbine power plant.

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The facility will compress air using off-peak electricity and store it in an underground limestone mine (Fig. 9). The mine was originally operated by the Pittsburgh Plate Glass Company between 1943 and 1976, producing the synthetic soda ash used in the manufacture of glass. The mine covers an area about 2130 m by 1220 m (7,000 ft by 4,000 ft, or 643 acres) and is built in a room and pillar mine configuration - rooms separated by pillars, leaving 9.6 Mcm (338 million cubic feet) of space. Although well below the water table, the mine is said to be virtually dry.

In situ and laboratory tests determined the permeability and integrity of the limestone and overlying shales and their capability to withstand pressure cycling. The limestone is a dense rock with few fractures, tests revealing it is capable of withstanding the planned operating pressure range of 55-110 bar (5.5 to 11 MPa, or 797 to 1,600 psi). Flow analyses and modelling indicated that pressurized air will move less than 30 m away from the mine in 50 years and will have no effect on the air compression and decompression cycling.

Construction will include two large concrete plugs closing off the two entrances of the mine, with layers of clay and tar within the concrete preventing leakage. Two boreholes, roughly 0.6 m in diameter, will be drilled, acting as valves for injecting and bleeding out the air.

2.2.10.2.4 Iowa stored energy plant

In 2003, it was planned to build the Iowa stored energy plant, which would be the first plant to use wind energy, as well as off-peak electricity to compress the air and store it in an underground aquifer (Haug, 2005). When generation is needed, the compressed air would be released to drive natural gas-fired combustion turbines. The proposal included building a wind farm, using 1.5-MW wind turbines.

Located near Fort Dodge, Iowa close to the electric transmission grid and a gas pipeline, the aquifer is Palaeozoic in age, which, during the 1960s was originally developed by Northern Natural Gas for natural gas storage. Part of the new facility could still be used to store natural gas indicating that the aquifer remains stable and with an effective seal. However, following further investigations, the geology may not be as favourable as was originally thought (Holst, 2005).

2.2.10.2.5 Markham, Texas

This is a planned salt cavern CAES storage plant being developed jointly by Ridge Energy Storage and El Paso Energy near Markham in Matagorda County, Texas (DTI, 2004; van der Linden, 2006). The projected start up date for the facility was 2005 and its configuration will provide a capacity of 540 MW (4 x 135 MW) of compressed air energy, which can be delivered in less than 15 minutes.

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3 Hydrocarbon seeps in petroleum-bearing basins

This chapter outlines the timing of oil and gas generation in some of the UK's oil and gasfields, indicating the length of time some of the oilfields have been stable and retained commercial hydrocarbon accumulations. The occurrence of hydrocarbon seeps in petroleum bearing basins is also outlined, drawing attention to the fact there are examples of both historical and active seeps onshore in the UK.

3.1 INTRODUCTION

The many commercial oil and gas accumulations worldwide attest to the sealing capabilities of caprock strata over periods of geological time (millions of years). The seal is generally provided by rocks with fine grain size that provide very small pore spaces, with poor connectivity (permability). The result is a rock with high entry and capillary pressures that only very slowly and under increased pressures, permit diffusion of hydrocarbons through the rock. Hydrocarbon accumulations have in some cases been trapped for hundreds of millions of years. This is true in the UK, with some of the oil in the East Midlands oilfields having been generated from late Dinantian and Namurian age source rocks buried to between 1900 and 3600 m by late Namurian times (c. 320 Ma). The oil and gas would have migrated into Westphalian reservoir rocks within both stratigraphic traps and ultimately structural traps formed during the late Carboniferous to Early Permian Variscan Orogeny (c. 310 to c. 280 Ma). Some of the earlier formed accumulations would have been disturbed by Variscan earth movements with oil and gas having leaked migrated away, perhaps to the contemporaneous land surface. Others probably remained intact. A second (Mesozoic) phase of oil and gas generation ensued from end Triassic times to the end of late Cretaceous chalk deposition (c. 65 Ma), when the structural traps formed during the Variscan movements were variously charged with hydrocarbons. This continued until strong uplift and erosion resulting from Alpine movements in Cainozoic times 'froze' the hydrocarbon generation (Fraser & Gawthorpe, 2003). During this time easterly tilting led to a second phase of trap disturbance and some remigration of oil and gas (Fraser & Gawthorpe, 2003; Hodge, 2003).

In the oil and gasfields of the Wessex-Weald basins of southern England, the source rocks are in the main younger Liassic clays (Lower Jurassic), although potential younger Jurassic source rocks exist and which may also have entered the oil generation window (e.g. Ebukanson & Kinghorn, 1985, 1986a&b; Penn et al., 1987). Burial history calculations suggest that oil generation from Lias source rocks would have begun during deposition of latest Jurassic and Lower Cretaceous sediments (from c. 142 Ma) and for Oxford Clay in the deepest basins from mid Cretaceous times (Penn et al., 1987). Oil generation probably peaked in late Cretaceous (65-70 Ma) to early Cainozoic (late Palaeocene; c. 55 Ma) times (Underhill & Stoneley, 1998). The oil migrated into tilted fault block traps formed during the active extensional phase of Meosozoic basin development, well before the major mid-late Cainozoic ('mid-Tertiary' - Miocene; c. 24 Ma) basin inversion events (Penn et al., 1987; Underhill & Stoneley, 1998). The basin inversion phase led to many of the early fault block traps being disturbed and a number of accumulations are thought to have been breached and hydrocarbons lost (Penn et al., 1987; Underhill & Stoneley, 1998). Some hydrocarbons may have remigrated into adjacent trapping structures, others may have migrated to surface and been lost. Clearly a number of oilfields survived in the area

It is perhaps noteworthy that early exploration was directed at obvious surface inversion anticlines and apart from the producing Kimmeridge Oilfield (Brunstrom, 1963; Evans et al., 2003), few hydrocarbon shows were encountered. These structures are now considered to be of low prospectivity by virtue of their structural style. The cores of the inversion structures are cut

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through by faults with reverse movement (which commonly penetrate to the surface) and also at shallower levels by sets of extensional joints and fractures (Bevan, 1985; Penn et al., 1987).

Prospectiviey of these structures is affected in a two ways:

- Hydrocarbons can (or could) escape up the fracture systems
- Meteoric water can invade from the surface, flushing the structures and degrading any petroleum accumulations

The Kimmeridge Oilfield may be the result of the Cornbrash reservoir being overlain by the Oxford Clay and a thick sequence of soft, plastic Kimmeridge Clay cropping out in the core of the periclinal closure. The clays effectively seal the producing fracture systems and preserve the hydrocarbon accumulation intact (Penn et al., 1987; Evans et al., 2003).

However, it has been argued that no reservoir cap rock or trap has ever been shown to be a perfect seal to hydrocarbon migration over extended periods of geological time (Nelson & Simmons, 1995). Studies have shown that migration of hydrocarbons out of the trap into overlying sequences (and sometimes to the surface), is more common than might generally be thought or presumed (Nelson & Simmons, 1995; Khilyuk et al., 2000; Nelson et al., 2005; Clarke & Cleverly, 1991; Cowley & O'Brien, 2000), with petroleum leakage to the surface presently occurring in at least 126 of the 370 petroleum-bearing basins worldwide (Clarke & Cleverly, 1991). It is, however, relatively rare for seeps to overlie major fields (Macgregor, 1993).

Natural pathways and mechanisms exist that include faults, fractures, microfractures and pore spaces in the caprock, which preclude a perfect seal. These result in hydrocarbon liquids and gases very gradually leaking from the reservoir rock. The hydrocarbons generally dissipate through the overlying sequences, sometimes reaching the earth's surface but in such small quantities and over such long periods of geological time that they rarely present a problem. The caprock, therefore, retards hydrocarbon migration, permitting the temporary (on geological timescales) accumulation of reserves within the underlying reservoir rock. It is, therefore, the rate of hydrocarbon flux across the field, achieved by migration along faults, fractures and microfractures, or by capillary action through the pore space that is of interest to the study of residence (or retention) time in any particular trap or field. If a concentration gradient (chemical potential gradient) exists, then molecular diffusion (by capillary action) is always present (Bockris & Reddy, 1970). This is generally regarded as the slowest loss mechanism and represents the minimum rate of loss from a reservoir over geological time (Nelson & Simmons, 1995). The various processes controlling migration are reviewed in section 3.3.

Gas is also found emerging at the earth's surface as a result of shallow biogenic sources, for example, marsh gas.

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3.2 UKCS OIL AND GAS SEEPS

Potential gas source rocks cover a large part of the UK Continental Shelf (UKCS) and include Quaternary peats, petroliferous source rocks such as the Carboniferous marine shales and Coal Measures and Jurassic shales, most notably the Upper Jurassic Kimmeridge Clay. Consequently, and although not widely reported they are more common than might be realised. Natural gas (and oil) seeps have been detected west of Ireland in the Porcupine Trough (Games, 2001) and are found over large areas of the North Sea seabed (e.g. Hovland & Summerville 1985; Vik et al., 1991; Hovland 2002; Hovland & Judd, 1988; Judd et al., 1997). In the North Sea gases (and other fluids) are found emerging through soft, fine-grained seabed sediments in the North Sea where they commonly produce a pockmark. These are circular to elliptical depressions on the sea floor, metres to hundreds of metres in diameter (Hovland & Summerville, 1985; Hovland & Judd, 1988). Onshore Great Britain, at least 173 occurrences of surface petroleum seepages and impregnations are reported, with oil and gas seeps reported from the East Midlands, NE England

and the Weald-Wessex Basin of southern England, where gas is found bubbling up along the south coast (e.g. Selley, 1992). The presence and discovery of these seepages drove the early exploration for oil and gas by D'Arcy/BP Petroleum and the Gas Council (Lees & Cox, 1937; Lees & Taitt, 1946). It should be noted that Selley *did not* include the many other seepages from the (considerable) outcrop of the Carboniferous strata on the UK mainland. Whilst it may be true to say that the overwhelming majority of such leakages have not been found to be associated with any existing oil or gasfield (Macgregor, 1993), it would be incorrect to say none are. The Formby Oilfield was effectively discovered because of significant oil stained soils and peats at surface above the oilfield.

In the context of the UK & the North Sea, the crust has, following glacial loading, undergone isostatic rebound several times through Pleistocene to recent times. Late stage hydrocarbon leakage and charging of reservoirs has been proposed in areas of the North Sea (North Viking Graben and Halten Terrace) as a result of repeated glaciations and de-glaciations during the Quaternary Ice Age (Statoil, 2004). This process may provide an explanation for breaching of some onshore/offshore UK fields and "pumping" of the hydrocarbons through the overburden to give us the evidence of seeps observed at the present day.

Estimates as to the gas flux across the UKCS show that natural gas seepages are significantly more important as a source of methane than had previously been established (Judd et al., 1997). Judd et al. (1997) concluded that between 120,000 and 3.5 mtonnes of methane are released from an area of 602,000 km^2, representing between 2% and 40% of the total UK methane emissions. Their work included onshore estimates from Abbeystead and Wigan (Lancashire) and Youlgrave (Derbyshire). This represents an average methane flux of 0.2 – 5.6 $t/km^2/yr$ over the whole UKCS and is somewhat higher than that estimated by Williams (1994) for all UK emissions of methane, both anthropogenic and natural, then totalling around 5 mt/yr and 107,000 t/yr, respectively. Gas flux rates are covered further in section 3.5.

As alluded to, onshore in Great Britain, hydrocarbon occurrences in the form of oil or gas seeps have long been reported. This includes the Wessex-Weald Basin area in southern England (see Selley, 1993), which has producing significant quantities of oil and gas since the early 1980s. The Weald Basin also has one of the first gas storage sites to have been developed onshore the UK, at Humbly Grove, with others also planned (refer Fig. 1 and Appendix 3)

The first documented discovery of gas in the Weald area came in 1836, when it was encountered bubbling up in groundwater during the digging of a waterwell at Hawkhurst in West Sussex around 17.5 km (11 miles) ENE of Heathfield (Pearson, 1903; Strahan, 1920). Workmen excavating and augering a pit by lantern light had reached 56 m (148 ft), within the Wealden Beds when there was a sudden rush of gas, which ignited, burning two workmen to death. Subsequently, in 1875, 1884, 1895 and 1896, further gas was reported in water wells in the area (Hirst, 1985), the latter two were drilled to provide water for use in a hotel and at the London, Brighton and South Coast Railway Company station (Dawson, 1897, 1898; Woodward, 1903; Strahan, 1920; Adcock, 1963; Hawkes et al., 1998). The well at the railway station became Britain's first natural gas well, consuming around 28.4 m^3 (1000 ft^3) per night to light the platforms (Pearson, 1903), the cumulative production for the well having been estimated at 566337 m^3 (20 million ft^3; Adcock, 1963).

Subsequently, an exploration borehole at Netherfield, Sussex, also encountered gas bubbling up through water that caused an explosion (Willett, 1875; Dawson, 1898; Pearson, 1903; Adcock, 1963). In 1902, following these discoveries, a company was set up to develop, distribute and market the gas in Heathfield, Polegate, and Eastbourne and further wells were sunk in the Sussex Weald. Oil and gas seeps were recorded from elsewhere in southern England (Strahan, 1920; Edmunds, 1928; Lees & Cox, 1937; Reeves, 1948). Such leakages have not, however, precluded the development of important oil and gas fields onshore, sometimes in close association with urban development in southern England and indeed in the East Midlands. Once the origin and

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likely presence of these seeps and accumulations became known, then the safety and precautionary measures taken during work reduced the number of incidents.

One of the worst tragedies involving civilian deaths in the UK occurred at Abbeystead, NW England on 23rd May 1984 and resulted from the accumulation of naturally generated methane in an underground tunnel (HSE, 1985; Pearce, 1985). Forty-four people were assembled in a valve house during a tour of the Wyresdale Tunnel complex. Shortly after pumping commenced, an explosion and fireball engulfed the visitors in the valve house, blowing off the buried concrete roof. For a period of 17 days prior to the tour no water had been pumped through the system and natural gas had built up in the tunnel, which on the commencement of pumping had been displaced into the valve house, where an unidentified ignition source was encountered. In all, 16 people were killed in the incident, with no one in the valve house escaping injury: all survivors suffered a mixture of blast, crush and burn injuries (HSE, 1985; Jaffe et al., 1997). The Wyresdale Tunnel is constructed in a series of rocks of Carboniferous age that contain source rocks for both oil and gas and that have led to commercial accumulations of hydrocarbons in this region (Fraser & Gawthorpe, 1990; Fraser et al., 1990; Kirby et al., 2000). The tunnel intersects a number of faults and the Grizedale Anticline (a fold on the northern margins of the NE-SW trending Ribblesdale Foldbelt -Aitkenhead et al., 1993; Wilson et al., 1989; Kirby et al., 2000) and in which, the gas appears to have initially accumulated.

3.3 HYDROCARBON MIGRATION

Hydrocarbon migration is largely buoyancy or hydrodynamically driven (Hunt, 1979; Klusman, 1993; Tedesco, 1995; Saunders et al., 1999; Brown, 2000), with chemical gradients driving some migration. Excellent accounts of natural gas migration and emission mechanisms are given by Schroot & Schuttenhelm (2003a&b), Heggland (1997), Heggland & Nygaard (1998) and Heggland (2005).

Visible evidence of petroleum leakage includes asphalt and tar deposits (more ancient seeps) or areas where oil or natural gas is actively seeping onto the ground surface, into mines or water wells, in springs, lakes, and marine coastal areas (see examples from California in the review of incidents – Chapter 9 and Appendix 5). Such surface sites showing visible evidence that liquid or gaseous hydrocarbons are actively leaking or have previously leaked from a subsurface region are called macroseeps (Link, 1952; Hunt, 1979; Weber, 1997). The migrating hydrocarbons follow the most permeable pathways to the surface, which are commonly faults and fractures. A second type of leakage is microseepage, which is oil or gas leakage to the surface that is not visible but which is detectable by analytical methods. Microseepage is detectable above subsurface petroleum reservoirs and also above natural gas storage reservoirs (generally aquifers) when the cap rock is not an effective seal for the reservoir rock (e.g. Jones & Drozd, 1983; Pirkle, 1986; Morgan, 2004; Jones & Pirkle, 2004: http://www.eti-geochemistry.com/FinalVersion1.10.htm: refer Chapter 9 and Appendix 5). A variety of analytical procedures have been developed for detecting petroleum microseeps (Nelson et al., 2005). The same factors apply to the determination of seal performance in proposed aquifer storage sites as are covered during oil exploration.

The following sections outline briefly the required components and processes important in determining the suitability and safety of any particular site for the development of a gas storage facility. The determinations are based upon a wealth of experience gained in the characterisation, development and production of hydrocarbons from oil and gasfields around the world.

3.4 CAP ROCKS, FAULTS AND SEALS

Caprocks or seals are an essential element in the development of hydrocarbon accumulations. A caprock is generally an overlying impermeable lithological unit (shale, salt etc) capable of impeding hydrocarbon movement. A seal maybe provided by a caprock or some other physical

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barrier such a fault or diagenetic boundary. Any lithology can provide a seal, all that is required is that the minimum displacement pressure (capillary entry pressure) of the seal rock is greater than the buoyancy pressure of the hydrocarbons in the accumulation. Capillary entry pressure in rocks is controlled by interfacial tension, wettability, and the pore throat size distribution (see below). Thus the size of the continuous pore throats and the density of the hydrocarbons and water are of great significance. The seal capacity is the maximum hydrocarbon column height that a seal can trap and can be quantified as the capillary entry pressure (displacement pressure) at which hydrocarbons will leak into a seal. This is often put at 5-10% nonwetting phase saturation (PTTC, 2004). The height of the hydrocarbon column trapped is equivalent to the sealing capacity of the weakest seal.

Three principal factors control capillary entry pressure in rocks (PTTC, 2004):

- interfacial tension between hydrocarbons and water
- wettability of the rock surfaces
- the size distribution of the pores, especially the interconnection of the pore throats.

Capillary pressure in a pore exists across the fluid interface between oil and water. The physical state of the interface is called interfacial tension when two liquids are involved and surface tension when a liquid and gas are involved. Absorption of a rock surface for a specific fluid is called wettability. If water is absorbed on the grain surface more strongly than oil or gas (water adhesive forces > cohesive forces), the grain surface is said to be water wet. The grain surface is oil wet if oil is absorbed more strongly than water (water adhesive forces < cohesive forces). In a simple capillary tube, the capillary pressure between a nonwetting phase (oil) and a wetting phase (water) can be defined in terms of the radius of curvature of the interface between the fluids, the radius of the capillary tube, the interfacial tension of the fluids and the wetting or contact angle.

Effective cap rocks for liquid and gaseous hydrocarbon accumulations are typically thick, laterally continuous, deformable rocks with high capillary entry pressures (i.e. they are impermeable). The most common caprock lithologies over commercial petroleum reservoirs are evaporites (mainly halite) and shales. Evaporites seal about 50% of the world's largest oil fields and 36% of the world's 25 largest natural gas fields (Hubbert, 1953; Berg, 1975; Downey, 1984; Grunau, 1987; Sales, 1997). However, carbonate-/silica cemented sandstones and cherts may also provide a cap rock.

Cap rocks, therefore, act effectively as valves that control the amount of liquid or gaseous hydrocarbons (the height of the oil or gas column) retained in reservoir rocks before the seal fails. Breakthrough pressure is the capillary pressure at which the nonwetting phase forms a continuous network within the seal. At this pressure, the nonwetting phase will leak or flow through the seal (PTTC, 2004).When the cap rock leaks, it and the overlying strata become partly saturated with oil and/or gas, which displaces the pore fluid initially present. There are many examples from the North Sea where gas chimneys have developed above fields and major structures (section 3.5). Leakage occurs by either:

- ***membrane seal failure*** can occur when gas transport is through the pre-existing pore system of the cap rock, either in solution in water or as a result of capillary failure (the pressure in the gas column beneath the cap rock may exceed the capillary entry pressure of the cap rock). This can arise as a result of either the buoyant force exerted by the vertical height of the hydrocarbon column in the reservoir and/or the existence of a chemical potential gradient across the caprock to drive diffusion. Membrane seal strength corresponds to the height of a hydrocarbon column that can be retained before leakage occurs. Determination of the capillary entry pressure and thus the pressure at

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which membrane seals start to leak can be ascertained by mercury injection tests performed in a laboratory using cap rock core samples.

Membrane seal failure is therefore, either

- pressure driven
- diffusion (molecular) driven

In aquifer storage sites which have generally not had high pore pressures (or depleting oil/gasfields taken to higher pressures than the original reservoir pressures), this could lead to a phenomenon referred to as exceeding the threshold displacement pressure (or threshold pressure), whereby the pressure is high enough to displace water-gas menisci in the rock pore spaces. The pressure displaces the static water column, forcing water out of the cap rock and leading to gas leakage from the storage formation (Katz, 1978). An inverse relationship exists between permeability and threshold displacement pressure, i.e. less permeable formations have higher threshold pressures.

- ***hydraulic seal failure*** – leakage may occur through hydraulic failure (microfracturing) of the cap rock, perhaps associated with faulting, i.e. or by under overpressures (see also Chapter 8). This occurs where the capillary entry pressure is essentially infinite and seal failure follows by pressure in the reservoir wedging open faults or pre-existing fractures or the development of fractures in the cap rock (e.g. Vik et al., 1991; Leith et al., 1993; Caillet, 1993; Nordgard Bolas & Hermanrud, 2003). The hydraulic seal capacity of a cap rock is related to such factors as its thickness and tensile strength, the magnitude of the minimum effective stress in the sealing layer and the degree of overpressure development in the reservoir system (Watts, 1987). Leak-off tests, performed in wells, are commonly used to determine the pressure at which hydraulic seals start to leak (Watts, 1987a&b; Sales, 1997). Katz & Coats (1968) found that no fracturing of the caprock occurred at or below pressure gradients of 22.6 kPa/m (3.28 psi/m) of depth, suggesting that it could only happen at pressure gradients of 33.9 kPa/m (4.92 psi/m) depth. However, gas might open existing fractures at gradients between 22.6 and 24.9 kPa/m (3.61 psi/m) depth. Such values are higher than the maximum overpressures resulting from original hydrocarbon entrapment and thus the overpressures used in underground gas storage projects should not exceed the original reservoir pressures.

  Studies of overpressured sequences across the Haltenbanken province of the North Sea have shown that well defined gas chimneys are numerous over structures and faults, indicating hydraulic fracturing of the caprock and release of gas (Vik et al., 1991).

- **Wedging open of faults due to tectonic activity** – a variant of the hydraulic seal failure mechanism that may be related to overpressures induced by tectonics

There is much written on the effectiveness of reservoir caprocks and rates of leakage through them by diffusion (e.g. Leythauser et al., 1982; Krooss et al., 1992a&b; Nelson & Simmons, 1992). Nelson & Simmons (1995) suggest that no caprock can be shown to be a perfect seal to hydrocarbon migration. Faults, fractures, microfractures and pore space in the caprock may often preclude a perfect seal, such that the caprock only retards migration, allowing the temporary accumulation (on geological timescales) of hydrocarbons within the trap/reservoir (Nelson & Simmons, 1995). Whilst this maybe true over geological time (millions of years), over the time period (perhaps 30-50 years) of a proposed depleted oil/gasfield UGS facility in the UK, it is likely that, providing original reservoir pressures are not exceeded, the caprock can effectively be regarded as fully sealing.

Faults can act both as barriers to fluid flow and as channels. The ability to predict which type of behaviour will have characterised a particular fault or fault segment and on what time scale, is of crucial importance in the hydrocarbon industry. Lithology is a key variable with, for example, faulting in sandstones capable of producing a sealing gouge. However, knowledge as to the

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extent to which fault surface geometry and the width and internal structure of the damage zone can also influence the permeability characteristics of a fault, is important. These parameters are themselves functions of lithology and are also likely to vary with time in a fault subject to repeated slip. Further review of studies on faults and fault sealing capacities in oil and gas fields is provided in section 6.1.

3.5 HYDROCARBON LEAKAGES AND FLUX RATES

As indicated, there are many documented accounts of hydrocarbons leaking to surface and which may also be dispersed to varying degrees in porous and permeable layers along its migration path forming secondary accumulations within them. Appendix 1 provides examples and levels of gas migration rates from/within hydrocarbon-bearing basins.

The most common mechanisms by which natural gas migrates through lithified strata is via faults and porous and permeable beds. The well-known gas seeps above the Tommeliten gas field in the Norwegian sector of the North Sea lie above a salt diapir or dome (Hovland & Summerville 1985). Faults above the diapir act as conduits for the gas rising from depth to the near surface (Hovland 2002), with gas also widely distributed throughout the upper part of the sediment column. An area of gas-charged sediments covering approximately 120,000 m^2 above the field is identified on seismic reflection data by a 'gas chimney': the result of the gas in the rocks degrading the seismic signal and the imaging of the strata within and beneath it (e.g. Hovland & Summerville, 1985).

In actively subsiding offshore sedimentary basins softer sediments including porous sandy or silty horizons, commonly occur, into which gas may migrate and move along, becoming dispersed. The gas may then become trapped in normal buoyancy traps beneath less permeable sediments such as clays. This results in the commonly observed shallow submarine seismic responses known as acoustic blanking, acoustic turbidity and reflector enhancement. As mentioned above, the gas often then emerges at the seabed in pockmarks (Hovland & Summerville, 1985; Hovland & Judd, 1988). Gas may also emerge through mud volcanoes, major examples of which occur, for example, around the shores of the Caspian Sea (Huseynev & Guliyev, 2004). They are stratified cones of mud on the seabed or land surface that originate when overpressured gas charged fluids migrate upwards through the less lithified strata in a sedimentary basin. They disrupt the overlying strata and rise as a column of fluidised sand, mud, gas, other fluids and blocks of sediment. At Tommeliten (Norwegian Block 1/9), where the sea bed is sandy, the gas emerges at the sea bed as bubbles, through small circular vents c. 10 mm in diameter in the sandy sea floor in a small part of the area above the gas chimney, covering about 6500 m^2 (Hovland & Summerville, 1985). The vents commonly have a cone-shaped depression about 20 cm in diameter. The gas bubbles have been observed using a remotely operated vehicle and have been imaged on echo-sounder and shallow 3.5 kHz seismic records. The gas seepage equates to about 24 m^3/day. Gas may also emerge through the seabed intermittently, in response to changes in hydrostatic pressure or to self-sealing mechanisms (Hovland, 2002).

A number of studies have been undertaken to calculate the diffusion rates and fluxes through a caprock. One study at the McClave Gasfield, a stratigraphic trap in the Pennsylvanian Morrow Formation (Carboniferous age) in southwestern Colorado, was undertaken (Nelson & Simmons, 1995). The reservoir lithologies are fluvio-deltaic sandstones within marine shales. Faulting is minor (generally less than 30 m) and there is little structural deformation. Therefore, any losses might reasonably be assigned to diffusion losses through/across the caprock. The methane flux over the areal extent of the field for 5% and 10% caprock porosities was calculated at 521 m^3/yr (18.4 mcf/yr) and 2382 m^3/yr (84.1 mcf/yr) respectively (Table 3), which would mean that the field's entire methane volume might be replaced every 2.21 million years (my) or 485,000 yr respectively, requiring constant recharge (Nelson & Simmons, 1995).

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Studies for hypothetical fields with a 1737 m thick caprock (Table 4), producing 283.2 Mcm and 2.8 Bcm (10 and 100 bcf) of gas have calculated losses of 2,832 m^3/yr (0.10 mcf/yr) and 21,294 m^3/yr (0.752 mcf/yr) respectively[4] (Smith et al., 1971). Nelson & Simmons (1995) suggest that these rates are comparable to those of the McClave Field, when differences in calculation scheme are considered. As might be expected, increased rates of loss are found with a thinner caprock of only 39.6 m.

The development of the conspicuous 'sage anomaly' above the Patrick Field in Wyoming, where sage and grasses were killed or showed stunted growth, was investigated for any relationship to the underlying oilfield (Arp, 1992). Studies of the geology and field production history revealed that the anomaly developed above the oilfield's gas cap following injection of produced gas and then water to repressure the oil reservoir and increase oil production. It is calculated that perhaps 2.5 Bcm (87 bcf) of gas (and light hydrocarbons) had migrated from the reservoir to the surface, via faults, at velocities of between 76.3 m/yr (over 20 year period) and 305 m/yr (5 year period). The latter rates are comparable to those calculated by Araktangi et al. (1982) for the Leroy Gas Storage Facility in Wyoming (section 9.2 and Appendix 2).

An incident occurred in northwestern Oklahoma on January 31st 1980, when natural gas began erupting at ground surface at a number of sites in the Edith area near Camp Houston (Preston, 1980). The venting initially created a crater 6.5 m wide from which a viscous mud was ejected to heights of up to 16 m. Within hours the venting had spread to an area roughly 2.4 km square, with several more large craters produced, linked by a series of fissures several metres long. The fissuring followed two orthogonal fracture sets in the Flowerpot Formation, a 100 m thick shale sequence and could even be seen affecting the overlying unconsolidated river deposits (Preston, 1980). Flow measurements from various vents ranged from 3,398 m^3/day (120,000 ft^3/day) to 7,646 m^3/day (270,000 ft^3/day). Flow from a large crater was estimated at over 56,633 m^3/day (2 million ft^3/day), with the total daily gas flow conservatively estimated at 0.57 Mcm (20 million ft^3/day). Investigations revealed that the gas originated from the Mississippian Chester limestone (the Chester-Oswego interval) at around 1700 m below ground and a faulty well was the prime suspect. Tests of the Leede Devine No.1 well indicated gas was entering the well at between 183 and 198 m depth, co-incident with a regionally extensive fractured evaporite interval, through which scores of wells had been drilled. Production tests (0.11 Mcm/day or 4 million ft^3/day) proved gas was entering the well bore between the wall rock and the production casing at that level. The well providing the route from the gas-bearing horizon to the fractured evaporites was never found as the ventings declined steadily and by August were of no great significance (Preston, 1980).

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[4] Where mcf/yr = one thousand cubic feet per year (not one million cubic feet per year)

4 Salt deposits and factors relevant to developing gas storage caverns

This chapter outlines some of the more important aspects and characteristics of salt deposits and consequently, how they may impact on the development of salt caverns for gas storage purposes. Further details of the nature of problems encountered at individual mines or brinefields (section 4.8) are available in Appendix 2 (refer also to Appendix 5).

4.1 INTRODUCTION

As alluded to previously, halite (rocksalt) generally occurs as a member of evaporite cycles in stratified layers, or as the thickened pillow and piercement structures (diapirs) resulting from halokinesis (the process of plastic deformation and buoyancy driven deformation of the source salt layers). The question of the rheological behaviour of the salt and the deformation history is of importance when assessing the long-term stability of any body of salt and thus caverns that might be constructed in it for gas storage purposes. This chapter, therefore, attempts to outline the rheology and deformation mechanisms of halite providing an outline of some of the basic properties of rocksalt that are required for input to modelling of salt tectonic processes and the assessment of mine and cavern stability.

4.2 SALT CREEP

The mechanical and rheological behaviour of salt is of great importance to the suitability and performance of salt beds for gas storage and some aspects are still open to debate (refer Bérest & Brouard, 2003). Salt may deform either in a ductile (plastic) or brittle manner, depending on the temperature, stress state and deformation rate (section 2.2.7). Salt behaviour is elastic-ductile when short-term compression tests are considered, but is elastic-fragile when tensile tests are considered (Bérest & Brouard, 2003). In the long term salt behaves as a fluid in the sense that it flows even under small deviatoric stresses. But its viscoplastic deformation and extremely low permeability are often referred to as strong reasons for salt beds being ideal sites for gas storage. This may be confusing and it is, therefore, worthwhile briefly reviewing these fundamental and often quoted properties. The effects of faulting on salt bodies or salt beds and the deformation mechanisms are dealt with in further detail in section 6.1.4.

Due in large part to interest in radioactive waste disposal and gas storage in salt, the last 20-30 years have seen a great deal of experimental deformation work undertaken on the deformation mechanisms and steady state creep of salt. As a result of this work and as alluded to previously, it is now well known and accepted that over a range of temperatures well below its melting point of circa 800°C, and under most normal burial (increasing temperature and pressure), engineering and geologically relevant conditions, halite deforms in a viscoplastic way (plastically). To all intents and purposes the halite will creep or 'flow' (e.g. Jenyon, 1986a,b&c). This is achieved by intracrystalline deformation processes (Fig. 6h-i), and probably by diffusive mass transfer (pressure solution) through thin intragranular aqueous (brine) films (Heard, 1972; Albrecht & Hunsche, 1980; Carter & Hanson, 1983; Wawersik & Zeuch, 1986; Skrotzki & Haasen, 1988; Spiers et al., 1989, 1990; Franssen & Spiers, 1990; van Keken et al., 1993 – see following section 4.2.1 for more detail). Increasing the temperature reduces the yield strength of halite, as does the application of differential pressure, although increasing the confining pressure seems to have a much smaller effect (Jenyon, 1986c). The presence of free water (brine) also reduces the yield strength.

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The creep mechanisms and processes involve the movement of dislocations (imperfections in the [salt] crystal lattice) through the crystal, dominated by cross-slip and/or climb controlled dislocation creep mechanisms (Fig. 6). Dislocations raise the energy of a crystal lattice and the process of dislocation movement is driven by the stress field and the crystal lattice trying to achieve its lowest energy level. It leads to lattice preferred orientations, dislocation substructures, subgrain formation and dynamic recrystallisation (see review of Carter & Hansen, 1983; Franssen & Spiers, 1990 and refer White 1976, 1977; Bell & Etheridge, 1973, 1976; Nicolas & Poirier, 1976 and Urai et al., 1986a for further details of intragranular/crystal deformation and recrystallisation processes).

It is important to note that crystal plastic deformation or dynamic recrystallisation mechanisms do not necessarily involve interstitial fluids, although natural salt bodies do contain trace amounts of brine. These remain from the formation of the salt beds, either as inclusions or as films on grain/crystal boundaries. Crystal plastic deformation processes are influenced by the presence of intracrystalline (inclusions) and interstitial water that causes hydrolytic weakening and leads to low temperature plasticity (e.g. Griggs, 1967; Sibson, 1977; Liu et al., 2002). Studies have shown that when trace brine is present, the creep of the salt can be significantly affected (refer 4.2.1 and 4.2.2 below).

Consequently, if caverns are developed in a salt body and the internal pressures are not kept high enough, differential pressures exist. The result of this natural process will be for the salt in the surrounding walls to very slowly creep/flow into the void and close the cavern. If left untouched (and with no water incursions), salt will creep into an unbreached cavern until the differential pressures are equal, with salt creep rates primarily influenced by:

- cavern depth and overburden characteristics – pressure and temperature gradients
- internal cavern pressure - where the difference between the natural lithostatic pressure and the cavern is high (low pressure in the cavern), then creep is accelerated relative to high cavern pressures.
- cavern shape
- salt properties – variations in crystal size and moisture content

This void closure phenomenon is well known in salt mines and brinefields and led to problems in some in some of the earlier salt cavern gas storage projects (sections 2.2.7.2 & 9.3 and Appendices 2&5). Cavern stability is dependent upon the composition of the salt, the geothermal gradient and overburden temperatures. At depths between 1000 and 2000 m there is an elastic-plastic transition zone. Salt creep above the transition zone occurs at slower rates and caverns are generally stable between depths of a few hundred metres and circa 2000 m (Warren, 2006). Below these depths caverns can show greater instability and large volume decreases through salt creep (Warren, 2006).

As with salt mines, solution mined caverns properly located, designed, constructed and operated above the lower depth limit can show remarkable stability, even when emptied of product as shown by the lenticular cavern in the Bryan Mound salt dome in Texas constructed in the 1950s (section 2.2.7). In contrast to the Bryan Mound example are the earliest purpose built gas storage caverns at the Eminence cavern storage facility (Mississippi, USA – refer Appendix 5). Here around 40% of the cavern volume was lost within two years of construction (Thoms & Gehle, 2000; Warren, 2006), and it illustrates how rapidly salt creep can occur with resultant loss of volume if operating conditions are not carefully controlled.

4.2.1 Creep behaviour of halite (rocksalt) in the temperature range 20-200°C and natural strain rates

Natural flow or steady state creep of rocksalt (halokinesis) generally occurs at (shallow) crustal levels where temperatures are relatively low, i.e. less than 150-200°C (e.g. Heard, 1972; Jackson

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& Talbot, 1986; van Keken et al., 1993). There are now many experimental studies to determine the deformation mechanisms and behaviour of a wide range of natural and synthetic salts under differing conditions (e.g. Carter & Hansen, 1983; Horseman & Handin, 1990 and see refs below).

The conditions investigated experimentally cover temperatures in the range 20°C to 250°C, strain rates in the range 10^{-4} to 10^{-10} s^{-1} and confining pressures up to 15-70 MPa. At experimental flow stresses approaching those in nature, i.e. below around 15 MPa and strain rates below 10^{-7} s^{-1}, experiments show flow by dislocation creep (Carter & Hansen, 1983; Wawesik & Zeuch, 1986). Concerning the rate controlling mechanism it has been argued that the main rate controlling process at 20°C to 200°C is probably cross-slip of screw dislocations (Wawesik & Zeuch, 1986; Skrotzki & Haasen, 1986). On the other hand, observed subgrain development at 100°C to 200°C indicates that dislocation climb might be the rate controlling process in this range (Carter & Hansen, 1983). Creep at 50°C to 200°C may also be controlled by cross slip at high strain rates ($<10^{-7}$ to 10^{-9} s^{-1}) and by climb at lower strain rates (Horseman et al., 1993, Carter et al., 1993). The nature of the detailed rate controlling mechanism remains unclear, although most salts show similar creep behaviour in the range 20°C to 200°C (van Keken et al., 1993).

4.2.2 Original brine in salt deposits and its migration through and effects on the rheology of salt bodies

In nature, minute amounts of original saturated brine (water) are found in rocksalt deposits, contained as either inclusions within the salt crystal lattices or along crystal/grain boundaries as films or in minor voids (refer Carter & Hanson, 1983). These minute amounts of fluid migrate gradually, under overburden or tectonic pressures, through the salt crystals and salt body. Studies on salt in the USA ("Project Salt Vault") estimated brine inflow rates of 0.5 to 3.0 ml/day at monitored boreholes, which amounted to 2-10 litres per hole after about 20-30 years. The flow rates approached zero after those times (Bradshaw & McClain, 1971; Carter & Hanson, 1983).

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The nature, shapes and migration paths of fluid inclusion 'bubbles' within rocksalt specimens subjected to temperature gradients in laboratory tests have been impressively demonstrated (e.g. Carter & Hanson, 1983; Urai et al., 1986). Studies and experiments have shown that even the minute quantities of inherent brine in a salt body may have profound effects on the rheology of salt. Water (brine) affects the mobility of dislocations within the crystal lattices, making it easier for them to move through the crystals. This affects significantly processes such as fluid-enhanced dynamic recrystallisation (Urai, 1983) and pressure solution creep or fluid enhanced grain boundary diffusional creep and grain boundary sliding accommodated by solution-precipitation.

Experiments on natural and synthetic salts, particularly finer grained salts, have shown that when trace amounts (typically $\geq$ 0.05 wt%) of brine are present at crystal/grain boundaries, then in addition to the dislocation mechanisms outlined above, deformation can occur by fluid assisted grain boundary diffusional creep or pressure solution at natural strain rates ($< 10^{-10}$ s^{-1}; Urai et al., 1986b; Spiers et al., 1986, 1988, 1989, 1990; van Keken et al., 1993). Naturally deformed salts show microstructural evidence for the operation of solution-precipitation (Urai et al., 1986b, 1987) and pressure solution creep may indeed become dominant over dislocation mechanisms. However, most salt deformation seems to be dominated by intracrystalline dislocation mechanisms (see Carter & Hansen, 1983).

At higher strain rates the deformation mode is likely to be that of dislocation glide, whereas at low strain rates there is a transition to pressure solution by grain boundary diffusion with dynamic recrystallisation along the grain/crystal boundaries. Also, lattice diffusion can occur, with water molecules passing through the NaCl lattice, which may affect the dynamics of the dislocation mode of deformation (Jenyon, 1986c).

4.2.3 Salt glaciers, rainwater and deformation mechanisms

Several in situ field measurements have shown that the downhill flow of salt glaciers is episodic, showing accelerated flow after heavy rain. In dry seasons, the movement involves only daily thermal extension and contraction due to variations in air temperature (Talbot & Rogers, 1980; Schléder, & Urai, 2007). There is evidence that these daily variations create an extensive and penetrative crack system (Talbot & Aftabi, 2004), which in turn is able to conduct the rainwater into the salt glacier. During the upward transport of the rocksalt, dislocation climb controlled creep and solution-precipitation creep are the main deformation mechanisms. However, as the rocksalt reaches the surface, numerous bedding parallel shear zones develop, in which the deformation mechanism is solution-precipitation creep (non-conservative grain boundary migration and grain boundary sliding accommodated by solution-precipitation). This is related to the ingressing rainwater, although the process by which this conducted rainwater wets the whole shear zone is not entirely understood (Schléder, & Urai, 2007).

The mass transfer, necessary for the solution-precipitation process, could take place in either static fluid network or in migrating fluid. The episodic glacier flow may imply that the mass transport occurred in migrating undersaturated fluids. This is perhaps borne out by the presence of numerous air inclusions at grain boundaries and triple junctions, which could be interpreted as the result of dissolution by the ingress of rainwater.

It is not thought likely that rainwater (fresh undersaturated water) will penetrate to salt in the regions and at the depths being considered for gas storage in the UK. Nevertheless, it illustrates that water can cause major changes in the rheology and deformation mechanisms of salt. Consequently, care is required to ensure that no pathways exist (e.g. old boreholes and poorly cemented new wells) to allow undersaturated water (or brine from wet rockhead entering via poor borehole conditions) to interact with the halite beds in which the caverns are to be constructed.

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4.3 GASES IN SALT FORMATIONS

Gases present naturally in salt sequences include methane (CH_4), nitrogen (N), carbon dioxide (CO_2) and hydrogen sulphide (sour gas - H_2S), the origins of which have been the subject of debate. Most domal salts in Louisiana are classified 'gassy' (Hinkebein et al., 1995) and miners have long known about the dangers of gas within salt formations: several fatal accidents in conventional salt mines have been caused by outbursts of methane gas and associated saltfalls (Molinda, 1988; Hinkebein et al., 1995). In June 1980 methane gas exploded at a salt mine on Belle Isle, Louisiana, killing 3 miners and injuring 17 others (Golden, 1981). The source of the gas is generally believed related to the fact that many evaporite sequences contain organic rich layers, produced during what are effectively algal blooms (Warren, 2006). On burial, gases are produced from these layers by bacterial sulphate reduction at low temperatures and nonbiogenically by thermochemical sulphate reduction at higher temperatures. It is suggested that some thin impurity-rich salt beds interlayered with beds having some porosity and permeability (so called 'carrier beds') leak small amounts of volatiles, but much less efficiently than the thicker organic rich shale and mudstone interbeds. Furthermore, movement out of the salt is unlikely until a pathway is available, generally as a result of the salt having been dissolved, or intersected by human activity in the form of boreholes or mining operations (Warren, 2006). The migration of methane gas over long distances through major salt deposits in Portugal, Yemen and NE Brazil has also been postulated, facilitated by fractures (Terrinha et al., 1994; Davison et al., 1996a; – see also section 6.1.4). These studies should perhaps be urgently reviewed as they may indicate problems of tightness not previously recognised or that might not necessarily be anticipated in salt bodies.

In the USA, problems have been encountered at UFS facilities (notably those of the SPR), in terms of the product inventory and delivery of stored product. There have been instances where

the volume of gas held in storage has increased due to gas generated within the salt body and which then moved through the salt body into the storage cavern (Hinkebein et al., 1995; Neal & Magorian, 1997). Gas movement into salt caverns has been attributed to permeation through the salt either through

- Release of gas contained in pockets in the salt (at lithostatic pressure) during solution mining. The theory is that the gas is contained in pressured pockets in the salt, which is considered essentially impermeable and the primary mechanism of gas release is from dissolution of the salt as the 'growing' cavern intersects the gas pocket. The gas released is presumed to be transferred to the blanket oil or to oil stored above the brine during leaching operations. Under this mechanism, blanket oil could contain a significant amount of gas, which would then mix with oil later injected for storage. If the mechanism is of primary importance, then the main gasification of oil would take place during oil fill and presumably little additional gas transfer would occur following the cessation of leaching.
- Permeation of gas contained in pockets in the salt (at lithostatic pressure). Gas permeation might be through two mechanisms
    - Stress induced permeability changes in salt surrounding caverns. Again, pockets of gas trapped in salt are intersected by zones of damaged salt around caverns that may arise during cavern construction/operation and which are caused by changes in the deviatoric stresses and pressures due to the cavern (void) formation (section 2.2.7.3.2.1). This may result in spalling of cavern walls in some cases (Hinkebein et al., 1995). This phenomenon has been observed in the Weeks Island mine where tracer gases have been injected in close proximity to the bulkhead and found to have moved through fractures in the salt that developed as a result of creep in the salt and the development of dilatant fractures in a disturbed rock zone around the bulkhead (Hinkebein et al., 1995)
    - Along anomalous zones intersected by the cavern (AZ's; Hinkebein et al., 1995; Neal & Magorian, 1997; – section 4.4).

Should AZ's form the main 'conduit' then this problem is considered unlikely in the salt beds of the onshore UK. AZ's are associated with shear zones developed during development of large salt diapirs and domes, which as noted in sections 5.3 and 11.2.7, are believed absent in onshore UK salt basins, although mild halokinesis may have occurred in the Weymouth area.

4.3.1 Gas in UK salt deposits

The Boulby Potash Mine in NE England has suffered from the presence of high-pressure gas in shaly parts of the potash, which have been sufficient to cause blowouts during mining operations (Corbett, 1996; http://www.mining-technology.com/projects/boulby/index.html). The presence of such gas in the Permian deposits of NE England should be of interest and perhaps of significance to any developers proposing to construct gas storage caverns. This would be both during the drilling and the cavern construction phases, when the brining process might encounter an unexpected pocket of high-pressure gas. It could conceivably also be of importance during cavern operation, if the facility was operated in brine compensated mode and there was ongoing leaching of the cavern during product cycling. A high-pressure pocket of gas might cause a blowout into the cavern as the intervening salt wall between the gas pocket and the cavern thins and cavern pressures change during retrieval of stored product.

4.4 ANOMALOUS ZONES

Anomalous zones (AZ's), as the name suggests, are unexpected regions of salt of differing character. In the USA they have been shown to affect cavern shape and at some sites, the storage

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operations for several reasons, often understood with hindsight (Neal & Magorian, 1997). They may be regions of more highly soluble salts (e.g. potash salts), fractured non salt interbeds, zones of sheared salt, or zones of older naturally leached salts ('Black Salt') which might contain pressurised brine or possibly gas (methane or nitrogen; Warren, 2006). AZ's might develop in brinefields and some salt mines near intersections with poorly documented older boreholes or brine wells. They have led to problems in some of the caverns that make up the US Strategic Petroleum (oil) Reserves (SPR), notably at Bayou Choctaw, Louisiana. Here, oil in two caverns showed higher than permitted gas content, which meant it required treatment prior to draw down (Neal & Magorian, 1997). A possible correlation of gassy caverns and a shear zone that transects the salt dome was found and it is suggested that the shear zones permit gas migration. Similar shear zones exist in other domes hosting the SPR facilities at Bryan Mound (Texas) and the Weeks Island and West Hackberry facilities in Louisiana (Hinkebein et al., 1995; Neal & Magorian, 1997). Apparent correlation of shear zones and gassy caverns supports work elsewhere on gas associated with salt outbursts in conventional mining (Iannacchione et al., 1984; Neal & Magorian, 1997).

In the UK context, anomalous zones might only be relevant in identifying non salt interbeds and layers of more soluble potash salts within the Permian salt basin. Onshore, salt deposits considered for storage do not show the development of halokinetic features. So the potential for shear zones that developed in the large diapiric salt dome structures seen in America is considered negligible. It may, however, be a phenomenon that requires careful study if salt storage caverns are developed offshore in the large salt ridges and domes of, for example, the Southern North Sea and East Irish Sea areas (see DTI, 2006c).

4.5 PRESENCE OF GYPSUM AND/OR ANHYDRITE

The presence of gypsum has long been known to represent a serious geological hazard that can arise from:

- Dissolution (it dissolves rapidly, especially in flowing water) that may lead to cave systems and collapse with subsidence in overlying areas
- During burial, gypsum converts to anhydrite and is associated with a volume change, which represents an important process in the burial history and evolution of a sequence of marine evaporites. It is also an important process in the gradual uplift and erosion of sequences containing anhydrite, which may convert back into gypsum

Evaporite deposits often include gypsum ($CaSO_42H_2O$) and/or anhydrite ($CaSO_4$). Given the above factors, determining the presence of one or both minerals in a sequence of shallow level evaporites could, therefore, be of importance when assessing any potential problems in a proposal to store gas in salt beds in which these minerals are present. Their presence may have a bearing upon the evolution of the evaporite sequence both during and post deposition. Phase changes could, for example, have caused local stresses that may have fractured adjacent rock and introduced a fracture system that requires study. However, for sequences that are deeply buried, the viscoplastic nature of the halite and the released brines are likely, over geological time, to cause infill of any fractures in the interbeds (section 4.6).

4.5.1 Dissolution of gypsum

Gypsum dissolves in *flowing* water about 100 times more rapidly than limestone, but only about one thousandth the rate of halite (Cooper, 1988). The rate is significantly less in more stagnant groundwaters where saturation is attained. The problem is well exemplified in the Ripon area of North Yorkshire where gypsum beds up to 30 m thick have been dissolved by subsurface dissolution (refer Cooper, 1986, 1988).

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The problem was also discussed in relation to:

- the rapid flooding of a gypsum mine and the effect on not only the gypsum, but any associated anhydrite (which would rehydrate and expand – see 4.6.2 below) and shales and limestone interbeds
- Water abstraction from gypsum sequences or where there is hydrological continuity could affect either natural gypsum-water systems or flooded mine workings. This could include large scale pumping from underlying coalmines.

4.5.2 Gypsum/anhydrite transition

As gypsum is buried and the ambient temperature rises above 42-60°C, it converts (dehydrates) to anhydrite (often a nodular form). This occurs at depths of around 1000 m, but is variable and dependent upon the geothermal gradient, lithostatic pressure and pore brine salinity (Borchert & Muir, 1964; Warren, 2006). Intense solar heating in very arid areas can cause dehydration of gypsum to form bassanite/anhydrite at the surface, whilst in areas of high geothermal gradients (80-105°C – not a UK range) it may occur at depths of less than 200 – 250 m (Warren, 2006).

The transformations not only release solutions that can trigger a series of important changes in the adjacent halite and, if present, potash beds, but are accompanied by a volume change (Borchert & Muir, 1964). Each cubic metre of gypsum is replaced by 0.62 m^3 of anhydrite and 0.486 m^3 of $CaSO_4$ saturated liquid is released. At 30°C, this volume of water can dissolve 0.081 m^3 of halite or 0.54 m^3 of carnellite. A bed of gypsum 5 m, 10 m or 20 m thick could convert to a bed 3.1 m, 6.2 m or 12.4 m thick (Borchert & Muir, 1964).

As rocks are uplifted and eroded away, the anhydrite beds at depth are returned to shallower levels and may remain largely unhydrated to within 100 m or so of ground level. What may happen is that the outer areas of the anhydrite body or beds may convert back to gypsum and protect an inner 'sandwich' of anhydrite. This could present problems if water were then to come into contact with the anhydrite. In the Ripon area, circulating groundwaters control the rehydration of anhydrite to gypsum, a transition that takes place at about 100 m depth (Cooper, 1986, 1988). As outlined above, this involves a forceful expansion of up to 60%, which can create extreme pressures and has been responsible for rock explosions and local uplifts in America (Brune, 1968; Cooper, 1988).

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4.6 FRACTURES OF NON-HALITE INTERBEDS AND INFILLING HALITE

The presence of fractures in rocks associated with gas storage is an important issue in the assessment of gas tightness and the safety of an underground storage facility. As discussed elsewhere in this report, halite rarely fractures and over geological time behaves in a viscoplastic way, healing any fractures that might have developed. Howeve, fractures may develop in salt in the walls immediately around the cavern margins due to the opening of a void (cavern) and releasing of the confining pressures. This is sometimes associated with spalling or breakouts of the wall and generally only forms a narrow zone, perhaps a metre or two wide (Rokhar, 2005 and section 2.2.7.3.2.1).

Fractures in halite are rare, but have been described (Terrinha et al., 1994; Smith, 1996; Davison et al., 1996a&b: section 6.1.3). Fractures in more competent non-halite interbeds and also the enclosing mudstone sequences are common. They may represent more than one episode of fracture formation and infill and generally show infill with halite or other evaporitic minerals such as gypsum or anhydrite (e.g. Wilson & Evans, 1990 – Fig. 10a). Some of the halite (and gypsum) infilling fractures has a fibrous habit indicating precipitation from a brine, but is also present as clear and coloured crystals of the same nature as the enclosing halite bed and not obviously deposited from a brine. It is, therefore, pertinent to assess the origin and likely

presence of any fractures and infill in such sequences and the likelihood fractures will remain open.

Cracks and fractures in non-halite interbeds may develop in a number of ways. They may be sedimentary and early burial features such as dessication cracks in silty mudstone horizons, most likely introduced to the salt basin during floods and which subsequently dried out. Alternatively, the fractures may be related to movement. Halite beds, although they may fracture if the strain rate is high enough and/or depth of burial is shallow enough (i.e. low temperatures and confining pressures), will tend to deform plastically under increasing heat and pressure (burial). In salt domes salt beds maybe drawn out to as little as a thousandth of their original thickness without fracturing (Borchert & Muir, 1964). Non-halite interbeds, however, being more competent than the enclosing halite deposits will tend to fracture and develop cracks during any deformation induced as a result of either burial or tectonic processes and the accompanying movement of the enclosing halite. Infilling halite might be the result of one or two main processes:

(a) Infill of fractures by precipitation from brines

(b) Non-brine infill origins (and fractures)

4.6.1 Infill of fractures by precipitation from brines

The presence of fibrous infilling material is suggestive of either dissolution and recrystalisation of the evaporite, or precipitation from saturated brines that remain within the halite deposits. All salt contains brine to a lesser or greater degree, remaining during burial either as inclusions within the salt crystals or as films along crystal/grain boundaries (e.g. Sonnenfield, 1984; Spiers et al., 1988, 1990; Warren, 2006). The fracture infills might originate in a number of ways:

- At surface and during early burial, dessication cracks may be infilled with halite precipitated out from brine, which might be as a result of the re-establishment of the brine lake or saltpans, or its presence in the substrate.
- Hypersaline brines of both syngenetic (derived from the same body that precipitated the original crystals), or epigenetic (derived from a body of water that did not crystallise the deposit and which may be slightly or significantly younger than the precipitate) origin. Being hypersaline concentrated brine, they do not dissolve the original precipitate but move through the precipitate along intercalations, encountering cracks or voids in the non-halite beds in which halite (or other evaporitic material) may precipitate. In consequence, depending upon the volumes of brine moving through the system, voids, cracks and fractures in the non-halite beds maybe sealed. Hypersaline brine movement may occur as a result of:
    - Gravitational instability allowing the brine to penetrate down, up or laterally into the precipitate (halite) body during its burial (e.g. Sonnenfield, 1984).
    - Expulsion of the brine on burial due to increasing pressure, whereupon it migrates and precipitates salt elsewhere.
    - Migration through the crystal lattices to areas/regions of lower pressure
- The dehydration of any interbedded gypsum to anhydrite above 42°C or at depths of around 1000 m (dependent upon the geothermal gradient), may have two consequences: firstly, there is a volume change that could lead to fracturing of non-halite interbeds (section 4.5.2) and secondly, it will also introduce liquid into a salt deposit, which can cause some dissolution of the halite deposit and the formation of a brine solution (Borchert & Muir, 1964; Warren, 2006). This could give rise to fracture infilling halite and gypsum/anhydrite. The latter would depend upon the location to which the fluid migrates.

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- Natural salt deposits contain small amounts of original saturated brine contained as either inclusions within the salt crystal lattices or along crystal/grain boundaries as films or in minor voids (section 4.2). These minor amounts of fluid migrate gradually, under overburden or tectonic pressures, through the salt crystals and salt body and could, therefore, potentially crystallise in cracks and voids in non-halite beds and seal fractures.

4.6.2 Non-brine infill origins (and fractures)

Some fracture infills may have arisen from processes other than precipitation. As halite deforms (plastically), more competent non-halite interbeds fracture and show pull-apart boudinage structures – joints and fractures (i.e. potential voids are created). Two sets of fractures may develop in the competent beds, more or less at right angles and perpendicular to bedding. The halite deforms by creep mechanisms, effectively flowing plastically around the boudinaged sections of competent materials, infilling fractures in the non-halite beds as they appear and propagate – akin to the process of extrusion. The resulting blocks of competent non-halite beds may be forced upwards or downwards into the enclosing halite deposits and may be rotated through any angle. Thin claystone/mudstone/evaporite rhythms may also be seen to break down into breccia-type deposits with angular fragments of competent material set in a halite matrix, all of which is achieved during, and as a result of, ductile flow of the halite.

It is also conceivable that under burial and increasing pressure, or due to some tectonic event causing an increase in pressure, some pressure solution of the salt might take place, similar to the process of fluid assisted grain boundary diffusional creep (section 4.2.1). If this occurs, small amounts of liquid might result and move along grain boundaries. The potential is for the salt solution to again migrate to, and crystallise in, cracks and voids in non-halite beds, potentially sealing fractures.

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4.7 WET ROCKHEAD AND SUBSIDENCE IN ONSHORE UK SALTFIELDS

The issue of wet rockhead is important for many reasons. These include issues of stability, increased movement of brine, which itself has damaging effects on borehole materials (cement and steel casings) and the likelihood of further salt removal that could lead to potentially damaging ground subsidence. Wet rockhead conditions have led to problems of product containment at the Conway salt cavern facility in Kansas, USA (Ratigan et al., 2002 – section 9.3 & Appendix 5). Saltfields in England are affected by the development of wet rockhead and thus the phenomenon requires careful assessment during the geological characterisation of any potential storage site.

4.7.1 Definition and origin of wet rockhead

Salt beds occur in the subsurface but unless in hot dry climates (e.g. the Persian Gulf area of the Middle East, where salt glaciers or 'volcanoes' can occur – see e.g. Kent, 1979, 1987; Talbot, 1979; Talbot and Jarvis, 1984; Warren, 2006; Bruthans et al., 2006), generally do not crop out at the surface. The reason for this is dissolution by circulating groundwaters. The solubility of halite is one to three orders of magnitude higher than the solubility of either anhydrite or limestone under normal groundwater conditions (Anderson & Browns, 1999). The dissolution of rock salt, in the presence of unsaturated water, is essentially instantaneous relative to the time scale of the relevant transport mechanisms (molecular diffusion, free convection and forced convection). The rate of solid rock salt removal is therefore controlled by the diffusive and/or convective flux of sodium and chloride ions away from a halite-bearing formation (Davies, 1989).

Circulating groundwaters can thus dissolve salt, with the area of dissolution being associated with collapse breccias. These collapse breccias are formed from mudstones that originally overlay, or were interbedded with, the halite in a region where the salt would have cropped out

had it not been dissolved (Fig. 11). The base of the breccia is known as 'wet rockhead' and is usually marked by the presence of brines, which have long been pumped to the surface (see e.g. Earp & Taylor, 1986; Wilson & Evans, 1990). As solution proceeds and the salt is carried away as brine, it leaves behind insoluble inclusions from the salt beds as well as the beds of stratified mudstone. Some of these beds are more than 10 m thick and alternate with the salt layers. Thus a zone of residual material (solution residue) is created at the outcrop in the stratigraphical position of the salt/mudstone sequence. There is also piecemeal sagging, collapse and brecciation of the overlying bedded mudstones within the salt, which are inextricably mixed with residue deposits from the salt beds (sometimes referred to as autobreccia – Earp & Taylor, 1986; p.51). The result is that all stratification is lost. The estimated thickness of this solution residue deposit in the Winsford area of the Cheshire Basin is about 53 m. This is the sum of all the mudstone beds in the Northwich Halite, together with the insolubles in the rock salt, estimated at 5% of the salt thickness (a figure widely accepted as an approximate average for impurity in the salt of Cheshire: Earp & Taylor, 1986; pp 51 & 53). As indicated, associated with the removal of the salt and the collapse of interbedded mudstone layers is collapse of the overlying overburden strata, which can lead to a thick collapse breccia beneath the drift deposits that may or may not retain a gross overall stratigraphy but loses all internal structure (Fig. 11).

Numerous cored boreholes in the Cheshire area have proved broken and collapsed strata above the salt, and it is not uncommon for a cavity to exist at rockhead. The few observations of the upper surface of the salt suggest that it is very uneven and deeply furrowed by solution channels. Many old records refer to a layer of granular marl, taken to be an insoluble argillaceous residue from dissolved salt; by its nature it has rarely been recovered from cored boreholes (Dickinson, 1882, p.79; Earp & Taylor, 1986). Dickinson (1882, p.79) summarised information from brine-shaft sinkers who described the top of the salt in the following manner: 'From what has been seen and is known of them, the spaces which a brine-run makes between the rockhead and the marlstone may be at first as thin as a sheet of paper, but the spaces become larger, and with the wearing away or solution of the rock-salt a peculiar structure of granular marl called 'horse-beans' ensues between the rockhead and the overlying bed of marlstone called the 'flag'. In this granular structure freer course is afforded for the flow. Spaces, at first only the size of rat-holes, become so large that a man can enter, and they increase into large caverns, and ultimately the ground about them subsides'. The 'horse-beans' and brecciated strata, in conjunction with the rockhead voids, act as an aquifer for the brine. Man has exploited this brine layer for brine extraction, creating deepened and entrenched channel systems (see below).

Downdip beds lie at a sufficient depth below circulating groundwaters that their contact with the overlying beds is a normal stratigraphical one, not associated with natural brine and is known as a dry rock-head. Solution of salt, seepages of brine and resultant subsidences onshore UK are thus of geological origin and not the consequence of Man's activity in the saltfield. However, Man's extraction of the brine product has, in cases, accelerated their development and enhanced their effects.

Natural brine development is controlled by both the depth of the salt body and circulating groundwaters: the closer to the surface (and circulating groundwaters) the salt body is, the more susceptible to dissolution it becomes. Despite the fact that the most abundant (Triassic) salt beds in the UK would have had between two to three kilometres of (younger) strata overlying them, most UK saltfields are affected by wet rockhead conditions to varying extents. Solution of the buried salt beds is a result of uplift, tilting and erosion having removed the overlying Upper Triassic, Jurassic and possibly even Cretaceous cover to bring Triassic salt within the influence of mobile groundwater. This is likely to have occurred since at least Cainozoic times (c. 65 Ma) and certainly since end-glacial times, circa 10,000 years ago. The slow removal of salt by solution progressed in parallel with, and at about the same rate as, the general lowering of the land surface by erosion. Thus the process of dissolution has continued since such times and much as it does today (Earp & Taylor, 1986).

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In late glacial times, when sealevel was unusually low, the solution rate in UK saltfields was probably accelerated temporarily as surface streams and most likely the brine seepages were rejuvenated. Conversely, during times of high sealevel the system would be sluggish with movement virtually ceasing over wide areas of rockhead. The modern-day UK conditions, where there has been no pumping, appear to be closer to the latter condition than the former (e.g. Earp & Taylor, 1986).

Away from present and past centres of artificial brine abstraction, the movement of brine and its replacement by freshwater is slow; the saturated brine layer protects the salt from further solution and there may be few records of subsidence (Earp & Taylor, 1986). Moreover, the routes over the 'wet' rockhead by which the brine moves appear to become stabilised for long periods, and so villages and churches with long histories of stability exist in areas of 'wet' rockhead.

Examples of the deepest recorded onshore instances of wet rockhead are in the Stockport-Knutsford district in Cheshire, where the salt 'crops out' against an undulating surface to the base of the collape breccia. This can vary between about 61 m (200 ft) and 122-152 m (400-500 feet) below present ground surface (Taylor et al., 1963). In the Chester-Winsford area, wet rockhead generally extends down to between 50 and 60 m. However, some brine channels adjacent to larger faults may be between 70 and 80 m below sea level, perhaps 100 m below ground level (Fig. 21 in Earl & Taylor, 1986). Collapse breccias overlying the top of the salt in the Winsford No. 1 Borehole indicates wet rockhead lies at a depth of 162.5 m (119.2 m below OD) with up to 12 m of salt may have been dissolved (Earp & Taylor, 1986; p.51). Wet rockhead may have been identified down to a depth of 180 m in other parts of Cheshire (Howell, 1984; Cooper, 2002). In NW England, wet rockhead is present in both the Preesall and Walney Island saltfields (Wilson & Evans, 1990; Rose & Dunham, 1979). An area of wet rockhead was mapped at Preesall, 0.5 km wide and extending to a depth of around 50-70 m below the base of the drift up to 0.75 km to the west of the Preesall Fault Zone (Wilson & Evans, 1990). The Walney Channel could be the site of a former brine run and an associated solution subsidence feature (Jackson et al., 1995). Offshore, beneath the East Irish Sea, wet rockhead may develop down to depths exceeding 220 m in for example well 110/9-1, and in the Calder and Morecambe fields where it is present in, for example, well 110/2a-8 (Jackson et al., 1987, 1997).

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4.7.2 Effects of brine exploitation on the features developed at wet rockhead

The earliest exploitation of brine was from springs occurring where natural seepages reached the surface either within or outwith the saltfield. This had no effect upon the natural regime of slow solution and subsidence, as the brine would have run to waste in the rivers. However, the discovery of plentiful saturated brine at the rockhead transformed the industry (Sherlock, 1921). This was accompanied by extensive damage from subsidence, as the ensuing large-scale pumping of the rockhead brine (referred to as 'wild brine') greatly accelerated the solution of the salt surface. The phenomenon is well known in the Cheshire Basin (e.g. Taylor et al., 1963; Evans et al., 1968; Earp & Taylor, 1986). This was particularly so at the points of entry of fresh water, where the established pattern of natural brine movement in the vicinity was radically modified (e.g. Ward, 1900, pp. 246 – 247; Earp & Taylor, 1986) and where subsidence has created depressions, craters, and often linear features. The latter were known as 'brine-runs' by the early brine miners (Howell, 1984; Cooper, 2002) and are channels, cut in the salt surface by fresh water that replaced the extracted saturated brine. Crater subsidences (Evans et al., 1968, p. 145) tend to form in regions of thick Quaternary sands and their formation can be sudden and unexpected, resembling the 'crowning-in' of flooded salt mines at Northwich (Earp & Taylor. 1986). Repeated enlargements of the craters can occur, which fill with water and empty at each collapse. Examples are described from northwest of Winsford, occurring in a well-defined linear belt related to an underlying fault that may have also enhanced the amount of water entering the system. The volume of sand that had subsided must have exceeded 50 000 m^3, indicating the size of the solution cavity at rockhead into which the waterlogged sands flowed. Evidence of direct

hydraulic connections between points along the brine-run is given by the simultaneous upward eruption of brine at one point along the belt with a new and sudden collapse half a mile upstream.

Examples of the linear features in the Cheshire Basin show maximum depths that average around 7.5 m to 10 m, with an overall width generally around 65 m to 75 m. They commonly exhibit a central flat-bottomed trough some 18 m to 22 m wide (Evans et al., 1968). They can form branching networks that are widened and deepened some distance away from the pumping stations, where the fresher water first came into contact with the salt and dissolution was most rapid and extensive (Evans et al., 1968; Earp & Taylor, 1986). Evidence in the Cheshire Basin is that some of these features show a strong linearity following the direction of strike and may, therefore, correspond to the subcrops of individual salt members at the 'wet' rockhead. The marl partings at rockhead are likely to form more resistant 'interfluves' between the dissolving edges of the salt layers (Earp & Taylor, 1986). Linear hollows may also follow fault-lines as shown by a group closely paralleling the King Street Fault between Warmingham and Crewe (Evans et al., 1968). The marls overlying the linear channel features collapsed, allowing more water to pass down and so intensified the cutting of channels and subsidence. Consequently, subsidence was not always close to the points of abstraction and often many kilometers away, such that the most distant parts of the induced brine streams are subjected to and exhibit the most active subsidence (Earp & Taylor, 1986).

4.7.3 Subsidence associated with salt mining activities and unrelated to wet rockhead conditions

Subsidence associated with the extraction of brine unrelated to wet rockhead conditions can be significant and require costly remedial work. This was the case in Cheshire where brine was pumped from shallow mines that had flooded. This, in turn, led to the solution of roof pillars, catastrophic subsidence and damage at the surface. Natural brine pumping also led to unpredictable subsidence some kilometres from the point of extraction. Damage caused by this method of extraction led to the cessation of salt extraction in Worcestershire and Staffordshire in the early 1970s. Remedial work to infill and stabilise the flooded salt mines beneath Northwich has recently started and similar work is planned in the Worcestershire and Staffordshire areas (BGS, 2006a).

There are also examples of major collapse hollows and deep craters associated with old ICI brine wells and caverns in the Preesall saltfield (section 8.7.2.1.1; Fig. 5b; Jackson, 2005; refer also Wilson & Evans, 1990). The topic of problems of subsidence in saltfields not related to wet rockhead or linked to gas storage is of particular interest when assessing the potential risks posed to existing or future infrastructure (gas pipelines, compressor stations etc.) in areas under consideration for gas storage in salt caverns and is outlined further in section 8.7.2 (Fig. 5b-d).

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5 Underground Gas Storage and areas most likely for development in Britain (including Northern Ireland)

In the light of Chapter 2 having described the main storage types, this chapter provides a brief review of the areas most likely to be considered for the development of UGS facilities *onshore* in Britain. UGS is only possible in certain geological strata or structures and these are present in a limited number of locations onshore in the UK. This section, therefore, briefly outlines the main hydrocarbon bearing/producing and salt bearing sedimentary basins, with a list of current operational gas storage facilities and applications to develop UGS (refer Table 1). Further details can be found in the BGS Salt and Oil & Gas factsheets (BGS, 2006a&b; http://www.mineralsuk.com/britmin/mpfsalt.pdf and http://www.mineralsuk.com/britmin/mpfoil_gas.pdf).

5.1 INTRODUCTION

There are a number of underground gas storage facilities currently operational or planned in the UK (refer Fig. 1), brief descriptions of each being provided in Appendix 3. In the UK, three quite different potential underground storage scenarios exist:

1. Pore storage – in depleted (or depleting) oil and gas reservoirs, involving injection of gas into the pore spaces of rocks that contained the oil or gas and formed the oil/gasfield
2. Construction of large voids either in:
    a. salt caverns within
        i. (thick) bedded salt sequences onshore Britain
        ii. salt domes (offshore in southern North Sea or East Irish Sea) –not dealt with in this report
    b. caverns/cavities in competent lithologies – not a option currently being investigated in the UK for natural gas, although the LPG storage caverns in the Chalk at Killingholme in N Lincolnshire show the success and potential of such facilities. However, compressed air storage in caverns might be possible and linked to renewable energy sources such as wind. Potential storage space could therefore be created in salt caverns (see 2 above)
3. Aquifer storage (pore storage similar to depleted oil/gasfields), but in structures that have not previously held hydrocarbons (either in commercial quantities or any at all).

Any development of aquifer storage will involve techniques similar to those in finding and developing oil/gasfields with the added requirement that additional work is required to prove the existence and performance of a caprock. However, the pressure on aquifers for supply of drinking water and the potential for contamination may make this option unlikely and is thus not considered as an option at this stage of the investigation for UK facilities

5.2 OIL AND GASFIELDS

Evidence of oil, both at surface and in mines and boreholes, are known in many areas of Britain. However, oil and gas have only been discovered and produced in commercial quantities from specific sedimentary basins onshore, where the required reservoir, caprock and, importantly, mature source rocks were deposited and where trapping structures now exist (Fig. 4a). Large areas of the UK are not prospective for oil and gas due to the absence or lack of one or more of

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these features. The productive basins have been explored for about 100 years and are now at a mature stage of exploration. Nevertheless, they continue to attract interest and large areas are licensed for exploration (Fig. 12). With improving exploration technology modest onshore discoveries continue to be made.

The age of mature source and reservoir rocks, and the type of hydrocarbons found (oil or gas) varies, the most productive defining a number of 'provinces' or producing areas (Table 5). Many of these provinces are not wholly onshore with, for example, the Wessex and Weald basins extending offshore into the English Channel. Similarly, the West Lancashire Basin is the eastern, onshore margin of the more extensive East Irish Sea Basin, and the East Midlands Oil Province and Cleveland Basin link to the Southern North Sea Gas Basin. In Northern Ireland prospective Carboniferous and Permo-Triassic sequences occur beneath the Antrim basalts in the north east of the province. Exploration continues but no commercial discoveries have, to date, been made.

5.2.1 Midland Valley of Scotland

In 1937, Anglo American discovered the small Midlothian oilfield, which only produced small amounts for a few years that were refined at Purfleet in Essex. Within a few months, D'Arcy Exploration, the forerunner of BP, made a gas discovery at Cousland along the same structural trend as Dalkeith. BP later returned to the site and for a time produced gas for local use.

5.2.2 North West England

The Formby Oilfield, about 17 km NNW of Liverpool, was discovered by D'Arcy Exploration in the Spring of 1939. The occurrence of oil had long been known in the vicinity, but the oilfield proved difficult to locate, being sealed by superficial deposits. The oilfield, which probably results from seepage of oil from a deeper accumulation, produced almost 72,000 barrels of oil before being shut down in 1965. Elsewhere, the only other success in the region was the discovery by British Gas about 10 km east of Blackpool in 1990 of the still operational Elswick Gasfield.

5.2.3 East Midlands Oil Province – Carboniferous play

The East Midland oil province comprises a series of major Carboniferous rift basins, within which sequences containing important source and reservoir rocks were deposited during Namurian and Westphalian (late Carboniferous) times. Early exploration led to the oil discovery at Kelham in the 1920s, after which exploration continued into the 1930s as the need to ensure oil supplies during the Second World War grew. In June 1939, BP discovered the Eakring oilfield about 23 km NE of Nottingham, confirming the East Midlands as a major oil province. However, wartime censorship meant that no announcement was made until September 1944.

Historically, the East Midlands province, comprising Lincolnshire, Nottinghamshire and the northern part of Leicestershire, has been one of the most prospective areas for onshore oil and gas in Britain. It is an area that has been subjected to only minor folding or tilting and faulting in post-Mesozoic times, such that hydrocarbon accumulations emplaced in post-Carboniferous times have not been greatly disturbed.

Since the Eakring discovery in 1939, many further important discoveries have been and continue to be made, including Gainsborough/Beckingham, Welton, Saltfleetby and Keddington. However, many of the older fields such as Eakring, Bothamsall, Egmanton and Kelham Hills are now shut down due to exhaustion of recoverable reserves and increasing water production. One or two oil discoveries have yet to be developed, including those of Broughton and Brigg. The current trend is for small focussed operators to identify smaller satellite structures to the main producing fields.

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Consequently large parts of the East Midlands have been and are currently licensed. Cumulative output of oil in the East Midlands is in excess of 6 million tonnes with the cumulative output from individual fields being in the range from a few thousand tonnes up to about 2 million tonnes.

5.2.3.1 Enhanced Oil Recovery (EOR) operations in the East Midlands Oil Province

Two notable onshore UK pilot demonstration EOR injection projects, overseen by BP Petroleum Development Ltd in the early 1980s, are known in the East Midlands oilfield region and may ultimately have relevance to gas storage operations. They are notable for the reason of injection of CO_2 and might provide useful background (in terms of the success or [reasons for] failure of individual processes) to any proposed schemes at these or closely related oilfields in the area.

A CO_2 miscible flooding project was undertaken at the Egmanton Oilfield in Nottinghamshire (Bradley et al., 1982; Grist et al., 1982; Bardon et al., 1983). The project was eventually terminated in 1983 on the grounds of prohibitive costs and the low injectivity of the formation having extended the project framework beyond the planned schedule. In a second project, surfactant flooding was conducted in the Bothamsall oilfield (Grist et al., 1982; Cooper et al., 1985), in order to assess the feasibility of using low concentration surfactant to release oil held in the formation by capillary forces (refer Fig. 4c). Although practical experience was gained in the handling of such surfactants, no marked response was detected at the producing wells to enable clear conclusions to be made regarding the effectiveness of the process.

5.2.3.2 Westphalian sandbody dimensions of the southern North Sea, eastern and northern England

Silesian (Namurian and Westphalian) sandstone and channel sandstone abundance and dimensions show systematic changes across the East Midlands, NE England and Southern North Sea (SNS), with sediment delivered to the basin from more than one direction (see Collinson et al., 1993). This is especially so in sequences of late Namurian and Westphalian A and B age, which form the major oil reservoirs of the East Midlands oil province. Depleting oil and gasfields in this region are being considered for conversion to gas storage facilities (refer Appendix 3) and a brief summary of their environment of deposition and dimensions is perhaps of use, providing background to reservoir characteristics input to modelling gas storage reservoirs (Figs 13&14).

The following is a brief review with more detail and provided in Appendix 7 following the review of different East Midlands oilfields. The East Midlands oil province lies within a major depositional basin: the Pennine Basin. This major depositional area existed in Britain during Dinantian and Silesian (Namurian and Westphalian) times and formed as a result of major crustal rifting processes. It lay to the north of the Wales–Brabant Massif and extended northwards towards the Southern Uplands of Scotland (Guion & Fielding, 1988; Collinson, 1988; Martinsen et al., 1995) and was gradually filled by enormous volumes of siliciclastic sediment (sandstones, conglomerates, siltstones, mudstones) and coals, which now form the Westphalian Coal Measures.

Within the Pennine Basin a number of smaller sub basins were formed and in which accumulated important source and reservoir rocks in central and northern England. The main reservoir rocks are of Silesian age, which onshore in the UK during Westphalian times, were in general, deposited across virtually the entire basin in a broad flat delta plain environment (see e.g. Fielding, 1984). Sediment patterns indicate that the sediment was introduced to the onshore UK coalfield areas from a northerly source through quite a narrow major channel feeder route located in the region of the present day Humber (Collinson et al., 1993). Some sediment was locally derived and supplied to the basin from the London Brabant Massif to the south in a narrow strip along the southern margin of the basin and the East Midland province. Within this

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area of deposition, various Westphalian channel sizes are recognised and summarised in Fielding (1984), Guion et al. (1995) and Aitken et al. (1999):

- proximal/lacustrine delta – 1-10 km wide with lobate to sheet-like deposits generally < 8 m thick.
- Major channels – 10's kilometres long, 1-20 km wide and typically 8-20 m thick
- Minor channels – up to 10 kilometre long, 10-1 km wide and typically 1-8 m thick
- Overbank deposits – elongate belts parallel to channels. Dimensions depend upon channel sizes, typically 1-8 m thick and 10's m wide
- Crevasse splay – minor delta developments along main channel resulting from overbank flow. Circa 1 km wide and 0-1 m thick, thinning away from channel centre

A relationship exists between channel width and thickness (Figs 13&14), with the maximum width being around 30 km and maximum thickness being around 50 m (but up to 100 m where sandbodies are amalgamated). Additionally, the data indicate that 90% of channel sandbodies are less than 25 km wide, less than 40 m thick and generally, reservoir intervals greater than 30 m will extend for more than 10 km perpendicular to the palaeoflow direction (Aitken et al., 1999). There is also a 35% probability of penetrating a relatively poor reservoir zone within the main channel belt, due to fine-grained horizons. These are interpreted to be partial abandonment channel reaches. By their nature and origin, these are difficult to correlate and may form potential baffles of up to several hundred metres in extent within the channel sandstone reservoirs.

5.2.4 Wessex-Channel (including the Weald) Basin

This prospective basin covers the Weald and Wessex areas in southern Britain, across which, oil and gas occurrences have long been known. Prospective sequences also extend offshore beneath the English Channel. A number of oil seeps have been documented inland, but most occur along the Dorset coast, from near Osmington in Weymouth Bay to Durlston Head (Selley, 1992 and Chapter 3). They include the famous Mupe Bay oil seep and the occurrences of gas bubbling on the seabed between Durlston Head and Anvil Point. Many oil and gas seepages are also known from East Sussex, the first discovery of which was in a water well being excavated in 1836. Similar discoveries led to the formation of a company in 1902 to develop and supply the gas to local markets at Heathfield, Polegate and Eastbourne (refer Chapter 3).

These oil and gas seepages and occurrences provided the early impetus for exploration in the area. Though results were initially disappointing, it did lead to the discovery of the Kimmeridge oilfield in 1959, which is still producing today. Exploration has been ongoing since then and in the early 1970s led to the discovery of the giant Wytch Farm oilfield. Production from this field has dominated onshore oil output. Ten other oil and gasfields have subsequently been discovered in the Wessex-Channel Basin and many are now depleting. One depleting oilfield has been developed as a gas storage facility (Humbly Grove - refer Appendix 3), whilst others (e.g. Albury and Storrington), being currently considered for conversion to underground gas storage.

5.2.5 North East England (including the Cleveland Basin)

In 1937 BP and ICI drilled at Eskdale and tested gas from the Permian Upper Magnesian Limestone. The field was developed in 1960 and the gas fed into the town gas system in the Whitby area until it was shut down in 1967. Subsequently, a number of other gasfields have been discovered along an E-W structural trend. The gas originates from Carboniferous (Westphalian) Coal Measures and has been trapped in fractured Permian limestones to create the now closed Eskdale and Lockton gasfields and the still producing Malton, Kirby Misperton, Marishes and Pickering gasfields.

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5.3 SALT BASINS

Salt (halite; sodium chloride, NaCl) is found in nature as solid rock salt (halite) or in solution as brine. The UK possesses important halite deposits, many of which were discovered during the search for coal in the late 1800s. Rock salt occurs in beds varying from a few centimetres to tens of metres in thickness, commonly associated with thin interbeds of mudstone, anhydrite and/or other evaporitic minerals. Individual salt beds and salt-dominated sequences may be hundreds of metres thick providing Britain with huge reserves of salt that is found in a number of areas and of differing ages (Fig. 1. Refer also to Mineral Planning Factsheet; BGS, 2006a [http://www.mineralsuk.com/britmin/mpfsalt.pdf]; Evans & Holloway, in press). There is no development of halokinetic structures in onshore UK salt basins, although some minor thickening of salt is noted into the core of the Weymouth Anticline, which might be related to early stages of salt movement during tectonism (section 11.2.7).

The most laterally extensive halite-bearing strata are of Permian age and lie concealed at depth beneath much of eastern England, from Teesside southwards through Yorkshire into northern Lincolnshire (Fig. 1). The halite beds form part of the Zechstein Group, which onshore represent the western margins of a large salt basin (the Zechstein Basin) that extended across the southern North Sea into Germany and Poland (refer Taylor, 1986; Ziegler, 1990) Within the Zechstein Group, halite formations are interbedded with thick dolomite, mudstone and anhydrite formations in five cycles (Z1-Z5). Each cycle represents a flooding of the southern Permian Basin from the north, followed by evaporation and drying out of the basin (Cameron et al., 1992). The halite beds thin rapidly westwards, but thicken and deepen to the east and south. The halite beds are east of the eastern limit of the predominantly carbonate sequence that lies along a roughly north-south line through central Yorkshire. These salt deposits have been exploited in two areas, referred to here as the Yorkshire and Teesside provinces.

Important rock salt deposits of Triassic age occur in NE England, NW England and the Cheshire, Stafford, Worcester, Somerset and Wessex basins (Fig. 1). The Triassic Mercia Mudstone Group (Mercia Mudstone Group) comprises a succession of mainly interbedded red-brown siltstone and mudstone, with gypsum or anhydrite and, in places, halite. Mercia Mudstone Group strata extend eastwards from Northern Ireland, across England and continue, with different lithostratigraphical nomenclature, beneath the North Sea, the Netherlands, central Germany and Poland. They represent ancient desert sediments deposited in a semi-arid environment consisting mainly of flat, low-lying plains, which were frequently flooded by seawater. At the time of deposition there was significant differential subsidence in this vast area and the main Triassic salt deposits onshore arise from individual basins that subsided more rapidly than surrounding areas, producing thicker and cleaner halite deposits than found on the basin margins.

Further salt deposits of Permian and most significantly, Triassic age, are found in Northern Ireland (Fig. 1), as proved in the Larne No.1 and No.2 boreholes (Manning & Wilson, 1975; Penn, 1982; Mitchell, 2004; Evans et al., 2006). In these areas, interest is being shown in developing salt cavern storage facilities in these salts. Three main salts totalling around 300 m in thickness are of Triassic age and lateral equivalents have been mined by both pillar and stall and solution mining methods to the south in the Carrickfergus and Eden areas. A Permian salt bed 113 m thick near the top of the Permian succession has also been proved by the Larne No. 2 Borehole. However the extent of the Permian salt is poorly constrained having only been proved in the area of South and East Antrim, although it is known to be absent towards the southern edge of the Larne Basin as proved by the Newmill Borehole (Evans et al., 2006).

5.3.1 Non-halite interbeds in UK salt basins

The thickness and relative purity of the UK salt beds can initially be relatively rapidly assessed from geophysical well logs, examples of which are described from the major salt-bearing formations in Britain by Evans & Holloway (in press). The geophysical logs all reveal the

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presence of generally thin non-halite interbeds within the Triassic salts. Of the main halite sequences that are likely to be suitable for gas storage (and which have undergone tests for this purpose), the Northwich Halite in the Cheshire Basin, the Preesall Halite in the Fylde area of NW England and the Dorset Halite succession in southern Britain all contain non-halite interbeds (Appendix 7, refer also Figs 54-57).

In the Cheshire Basin, the Northwich Halite contains non-halite interbeds that are generally on the metre scale and are more frequent in the upper half of the formation, but includes the 'Thirty Foot Marl' in the lower third of the succession (refer Figs 54&55). The Portland No. 1 well drilled in 2006 (Egdon, 2006a) reveals mudstone interbeds increase in number towards the base of the Dorset saliferous beds.

Two geophysically logged boreholes (one fully cored) drilled through the Preesall Halite during early 2004 for the Preesall investigations reveal generally thin mudstone and anhydrite interbeds are present in the western unworked area of the saltfield (Ratigan, 2005; Evans et al., 2005). Three more prominent zones of salt and non-salt interbeds 5 m, 6.19 m and 6.54 m thick were encountered, with the maximum individual non-salt bed thicknesses in these zones between 1.04 m and 1.76 m (Ratigan, 2005). Gamma ray logs from the older ICI brine wells and the Canatxx wells reveal a consistent halite stratigraphy that can be traced along the western boundary of the brinefield (Evans & Holloway, in press). An abnormally thick (17.5 m) mudstone is reported in a very old shaft in the east of the saltfield. However, the thick mudstone proving is at odds with sequences in surrounding boreholes and shafts and it is suggested that the records in the area, being very old and unsatisfactory, cast doubt on the accuracy of the logged sequences for that shaft (Wilson & Evans, 1990). The present information indicates that the Preesall Halite, the lateral equivalent of the Northwich Halite of the Cheshire Basin (Warrington et al., 1980; Wilson, 1990, 1993), contains fewer thick mudstone interbeds than the other Triassic salt fields in the UK and within the saltfield, the interbeds thin westwards into the basin (Evans & Holloway, in press). The salt is equivalent to thicker halite sequences offshore containing fewer mudstone interbeds (e.g. Jackson et al., 1987, 1995; Jackson & Johnson, 1996).

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5.4 AQUIFERS

As mentioned above, although aquifer storage is successfully undertaken in a number of countries including France, it is not currently perceived as an immediate prospect in the UK. This is for a number of reasons, which primarily include the higher costs associated with developing such a facility when compared to other options. However, other issues, including how such facilities might be covered by current UK legislation and regulatory bodies, would require clarification and further input from, for example, the Environment Agency and Government.

As stated, however, aquifer storage facilities exist elsewhere at for example, Spandau, beneath Berlin and at various sites around Paris. For completeness, therefore, the likely areas in the UK that might in future be regarded as having potential are indicated in Figure 15. The figure shows the main aquifers at outcrop in the UK and the reader is referred to Allen et al. (1997) for further details on UK aquifers.

5.5 PREVIOUS INVESTIGATIONS INTO STORING GAS IN POROUS STRATA IN THE UK ONSHORE AREA

In the early 1960s, the Gas Council's London Research Station had begun exploring the possibilities at a number of onshore sites for the development and control of underground (town) gas storage in Great Britain (Johnson, 1962; Holloway et al., 2006). The plan was to identify geological structures with porous formations, which could be safely used to store town gas and initially was targeted at the Lower Greensand (Cretaceous age) in both the Winchester Anticline in Hampshire and the Cliffe Anticline on the borders of Essex and Kent. The vast majority of

sites were located outwith the main sedimentary and oil and gas producing basins, being on the London-Brabant Platform: an area of relatively shallow Variscan basement. All structures eventually tested were initially identified on gravimetric anomalies and drilled to establish the structural high. However, not all the wells reached the intended reservoir, as the purpose was to drill quickly and to establish the structure. A systematic search in the Midlands followed in an area SE of Birmingham between the towns of Cheltenham, Warwick, Northampton and Banbury. This lay near national pipelines but away from urban development. The Triassic Keuper Sandstone (now known as the Bromsgrove Sandstone), which pinches out at depth to the SE against the London Platform, was identified as the most likely reservoir horizon. Overlying Mercia Mudstone Group strata provided the seal.

Exploration ceased during the mid 1960s due to imports of LNG from Algeria and the gas discoveries in the North Sea. The location of the geological structures investigated is shown in Figure 1, brief descriptions of which follow.

5.5.1 Winchester Anticline

The Winchester Anticline in Hampshire was first drilled by the Gas Council (GC) and BP's joint venture to explore for gas, in 1959. The first of five deep wells reached the Lias (TD[5] at 1781m bgl) and the subsequent wells were terminated in the Purbeck-Wealden (TDs about 600m). The GC returned in 1962 to drill 30 wells to appraise the potential for gas storage. Several of these wells were drilled through the Chalk and Upper Greensand into the Gault.

5.5.2 Cliffe Anticline

In 1959, a series of 10 wells was drilled and geophysically logged by BP and Schlumberger on behalf of the GC, on the Cliffe Anticline, which crosses the Thames from Tilbury Marshes in Essex to Cliffe in Kent. Chalk crops out in the core of this anticline. Two of the wells were sites on the Essex coast and two were farther south. All wells penetrated the Lower Greensand, which was probably the target storage reservoir with the Gault appearing to offer potential as a cap rock (Johnson 1962). The southern two boreholes reached strata of probable Devonian age. These wells were part of the gas storage programme (Johnson 1962; p158) although they were drilled before it officially started in 1960.

Another shallower series of 20 wells was drilled and geophysically logged in 1961. Four of these are located on the Essex shore, although no geological reports exist for these boreholes. The majority of these wells terminated in the Lower Chalk and it is thought the location had not been completely investigated (Johnson, 1962).

5.5.3 Napton

Eight shallow wells were drilled at Napton in 1961. The area was considered unfavourable due to faulting (Johnson 1962).

5.5.4 Stow

About 31 wells were drilled near Stow-on-the-Wold, to appraise the potential for gas storage, in 1961. The target is assumed to have been the Keuper Sandstone. Not all the wells reached the Keuper Sandstone, which in this area, lies at about 100m below sea level.

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[5] TD = terminal depth (final depth) of the borehole

5.5.5 Chipping Norton

During 1962, 340 wells were drilled over a large area near Chipping Norton, with the aim of 'structure proving for gas storage'. Cores were taken in the Keuper (Bromsgrove) Sandstone and in the Upper Coal Measures in GCN 1 well and it is, therefore, assumed these were the reservoir targets.

5.5.6 Brackley

Eighteen wells were drilled in 1963 in the vicinity of Brackley (NGR: SP53NE) for the purposes of 'structure proving' for gas storage. The wells spudded into Middle Jurassic strata and the target may have been the Keuper (Bromsgrove) Sandstone, although not many of the wells reached this stratigraphic level.

5.5.7 Huntingdon

Fourteen wells were drilled near Huntingdon in 1964. These mostly spudded into Oxford Clay and many reached Devonian and older rocks. The reservoir target was probably thin sandstones at the base of the thin Triassic sequence or basal Lias. These sandstones were not present in some of the wells because of overlap by Jurassic strata.

5.5.8 Nene

Two wells were drilled in 1964 by the GC, 'proving underground structure' near Raunds, Northamptonshire (NGR: SP97SE). One reached Carboniferous. The Keuper (Bromsgrove) Sandstone was the likely target reservoir.

5.5.9 Stamford

Fifty-two wells were drilled in 1964 near Stamford 'to prove structure and sequence'.

5.5.10 Sarsden

About 10 wells were drilled near Sarsden (NGR: SP22SE) in 1965-1966, which were probably also for gas storage exploration. The intended Keuper (Bromsgrove) Sandstone is unconformable on Carboniferous strata at depths varying from 80-96m below sea level.

5.5.11 Whichford

Three wells were drilled at Whichford (NGR: SP33) 'proving geological structure' in 1964 and which were also part of the gas storage exploration. The intended reservoir was the Triassic Keuper (Bromsgrove) Sandstone overlying Carboniferous strata at about 150m below sea level.

5.6 CURRENT UGS FACILITIES AND APPLICATIONS IN ENGLAND

Current operational UGS facilities are in depleted oil and gas reservoirs and salt caverns onshore in England and are summarised individually in Appendix 3. They include Hatfield Moors (depleted gasfield), Humbly Grove (depleted oilfield), with salt cavern storage at Atwick/Hornsea, Holford, Hole House and at Saltholme and Wilton on Teesside (refer Fig. 1).

In addition to those operational facilities, there are a number of gas storage projects that are currently under development/construction or in the planning stage (see Fig. 1 and Table 1). The proposed facilities currently in the scoping, planning application and development stages are summarised individually in Appendix 3. Further details of the operational and proposed salt cavern storage sites may also be found in Evans & Holloway (in press).

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As alluded to in the introduction to the report, most UGS applications in the UK are faced with strong local opposition and generally become involved in lengthy public inquiries. A major shift was, however, noted during the application to develop a salt cavern facility at Stublach in Cheshire (refer Appendix 3). A further important development in the planning applications for UGS facilities has been the move by Star Energy in late 2006. Having experienced what the Company believed to be unreasonable delays to its planning applications, in October 2006 the Company announced its intention to use the 1965 Gas Act for all of its UK onshore gas storage applications (Star Energy, 2006). The Company believes that the use of the 1965 Gas Act will provide a more certain timeline and cost for future gas storage planning applications, and to this end the Company anticipates submitting planning applications under the Gas Act in the first half of 2007 for Welton and Albury Phase 1, and for Gainsborough in the second half of 2007.

In addition, there are three schemes offshore in the East Irish Sea and Southern North Sea worthy of note at this stage:

- Kinsale Area Gasfields, offshore Ireland - the Kinsale Area gasfields are located off Cork in the south of Ireland. They comprise the Kinsale Head, Southwest Kinsale and Ballycotton Gas Fields and are owned and operated by Marathon. The Kinsale Head Gasfield was discovered in the Lower Cretaceous Greensand in 1971 and started production in 1978. The field is produced through two platforms, Alpha and Bravo, with Bravo production routed through the Alpha platform, co-mingled with the Alpha production and exported via a 24 inch pipeline to the onshore distribution system.

  However, the gasfield depleted and following preparatory work in 2000, the Kinsale Gasfield became Ireland's first seasonal production facility in 2001, when the southwest lobe of the Kinsale Field was converted for gas storage. The depleting reservoir is recharged during the summer months, with gas re-produced and delivered to the market in the winter months, when demand is higher.

- The 'Gateway Gas Storage Project' is a proposal to develop natural gas storage caverns at a depth of around 550 m below mean sea level (msl) in the thick Triassic halite offshore in the East Irish Sea Basin, approximately 30 km offshore to the SW of Barrow (Stag Energy, 2006, 2007). This proposal followed an announcement by the Secretary of State for Trade and Industry that, following a review to the DTI that concluded salt deposits suitable for gas storage development were present in the East Irish Sea and southern North Sea (Smith et al., 2005). The UK Government is keen to pursue the potential to develop such offshore sites to complement the requirement for gas infrastructure (DTI, 2006g).

- In December 2006, EnCore Oil plc announced that a subsidiary, Virgo Energy Limited ("Virgo"), had entered into an agreement with Star Energy Group plc ("Star Energy") for Star Energy to farm into Virgo's UKCS Block 43/8 Forbes field (Southern North Sea). As part of the deal Star Energy will undertake a feasibility study and a 3D seismic survey to determine the potential to use the Forbes field as a gas storage facility.

  Developed initially by Hamilton Oil, the original gas in place was in the order of 100 bcf (2.8 Bcm) and the field produced approximately 48 bcf (1.36 Bcm) of gas, via a tie-back to the Esmond field, prior to abandonment. Preliminary studies undertaken by Star Energy indicate the field has potential for development as a high performance gas store with up to 50 bcf (1.42 Bcm) of working gas capacity. Importantly, the field has a reservoir of high quality, has cushion gas in place and is close to major infrastructure. Under the terms of the farm out agreement, Star Energy will undertake a feasibility studies and assign 50% of its interests in the Eskdale (PEDL 002) onshore licence to Virgo. The farm out agreement allows Star Energy to earn up to 50% of the Forbes licence and to become operator if the field is developed into a gas storage facility.

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6 Faults, faulting and fractures in salt sequences and UK seismicity

This report clearly focuses on the concepts and geology of underground gas storage and problems that have arisen (or could arise) at UGS facilities. Faults and their movement histories are key controlling elements in fluid flow systems in sedimentary basins. To many, the presence of faults is seen as detrimental to a system that may be used to store injected gas. In terms of the safety and the gas tightness of any proposed storage site, faults could provide pathways to the surface for any gas held in storage or that has escaped from storage to an intermediate level intersected by faulting. However, faults do not necessarily reduce the effectiveness of a structure to retain oil and gas. Indeed, many oil and gasfields around the world have highly fractured or faulted reservoirs with closure and seal provided by one or more faults. Examples exist in oil/gasfields both offshore in the northern North Sea, where of the 250 or so hydrocarbon finds, 70% are in fault block traps (Spencer & Larsen, 1993), and onshore in the UK. The latter include Wytch Farm (the largest onshore field in Europe; Bowman et al., 1993; Hogg et al., 1999; Katterhorn & Pollard, 2001), Humbly Grove-Herriard oilfield (already a gas storage facility; Hancock & Mithern, 1987; Trueman, 2003; Star Energy, 2006) and the Saltfleetby Gasfield (Hodge, 2003; already a proposed site for gas storage).

The differing role of faults in the development of oil and gasfields is illustrated in the Wessex-Weald Basin in southern England. Oil migration from the main 'kitchen area' offshore in the Channel Basin into reservoirs in tilted fault blocks to the north of the Purbeck-Isle of Wight fault system requires that the faults acted as migration pathways. These must have been sealed over by the Upper Cretaceous at the time of maximum migration to prevent escape to the surface. The faults subsequently became sealing, perhaps due to the onset of compression during the 'Tertiary' basin inversion phase (e.g. Selley & Stoneley, 1987; Underhill & Stoneley, 1998). Clearly, the fact that these structures onshore the UK contain commercial accumulations of hydrocarbons attests to the fact that the faulting present has not prevented their retention over significant periods (millions of years) of geological time (section 3.1).

Determining the presence and sealing potential of faults or fractures in the sequences in which it is proposed to store gas, including the deformation of halite beds, is therefore of clear importance. Many factors have to be taken into account when assessing the sealing or leaking capacity of faults and fault systems and the gas tightness of the storage environment. This process includes modelling and assessing the performance and behaviour of faults under differing conditions. In depleting oil or gasfields this would include modelling the increase and cycling of pressure back up to original reservoir pressures and the impact this inflation would have on any faulted reservoir or caprock sequence. In salt caverns, it would also include modelling the presence of faulting in sequences enclosing the halite beds and the effect of cavern formation and gas injection to the stability of the fault.

Faults, associated rocks and seismic effects cover a huge range of topics and this section does not attempt to deal with them in detail. Rather it intends to provide some essential terminology and background to the processes that will be undertaken in order to assess faulting (and its consequences) in the sense of its importance to gas storage. If required, sources of information for further reading are indicated. It is also pertinent to review seismicity related to UK faults and its bearing on the safety of any such facilities developed.

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6.1 FAULTS, FAULT TERMINOLOGY, SEALING POTENTIAL AND FAULTING OF SEQUENCES CONTAINING HALITE

This section briefly outlines fault terminology and aims to aid understanding of the nature of deformation of halite in nature. In reading it, reference should be made to section 6.1 and the glossary, which includes a cartoon sketch diagram to illustrate faulting of strata and terminology.

6.1.1 Terminology

A 'fault' is defined as a fracture in rock, along which there has been a measurable amount of displacement. Faults are rarely simple planar units, but normally occur as a series of parallel or subparallel faults (forming an anastomosing network) along which movement has taken place to a greater or lesser extent and forming a fault or fracture zone. Only when a fault intersects the earth's surface do we see a major downstep across the fault (rupture) and the 'creation of space'. Faults may have had some movement during deposition, but have generally also moved after the sediments were deposited and rock layers ('beds') formed.

In the subsurface, therefore, movement on a fault surface displaces the stratigraphical units of the hanging-wall (downthrown fault block) relative to the footwall (upthrown fault block) past each other along the fault plane (Fig. 16 & Glossary). In the absence of any entrained material within the fault zone, if displacement on the fault juxtaposes impermeable units (e.g. shales; seals) against permeable (e.g. sandstones; potential reservoir) units, then this can seal faults to cross-fault hydrocarbon flow and hence control hydrocarbon trapping (Allan, 1989; Clarke et al.). Fault seal and juxtaposition of lithologies is discussed in more detail in section 6.1.2.

Although a fault can be a thin clean break between two rock masses (hanging and footwall fault blocks), during the process of faulting the rocks are commonly broken up to a greater or lesser extent, forming a zone of damaged strata along the fault. Such processes that operate within the fault zone during deformation are collectively referred to as fault-zone processes. As alluded to above, they can generate a gouge of material between faulted blocks referred to as fault rock or fault-related rock (Peacock et al., 2000). Such material can have lithological and petrophysical properties very different from those of the faulted blocks between which it resides and hence act as a further influence on the migration of hydrocarbons between faulted blocks. Dependent upon the hardness of the rocks and the depth of the faulting, various fault rocks are produced. At shallower levels (the brittle zone, where faulting results in seismic shearing), hard rocks are crushed and broken (cataclasis). The process forms fault breccias comprising angular fragments of varying size. Continued or more intense fault movement, perhaps with the entry of fluids into the fault zone, may further reduce the size of the rock fragments to rock flour or fault gouge. Shales, mudstones and clays will, due partly to the phyllosilicate minerals present, tend to deform more plastically, being drawn out and smeared along the fault during faulting. These minerals also more readily undergo recrystallisation during deformation, enhancing the plastic deformation of shales/mudstones/clays (section 6.1.2.1 below). At greater depths the rocks will deform by aseismic shearing (crystal plastic deformation processes) such that the rocks do not fracture, but develop in (wider) ductile shear zones (producing, for example, mylonites). The depths at which the brittle-ductile transition takes place are temperature, pressure and strain rate dependent but would typically be from c. 15 km depth (refer Sibson, 1977).

Most fault zones comprise a series of anastomosing faults, forming a branching network of intersecting faults. Modelling and observation of intersecting faults indicates the development of strongly dilational zones in the vicinity of fault intersections (Sanderson & Zhang, 1999; Zhang & Sanderson, 2001; Gartrell et al., 2004). These studies reveal that relatively large fracture apertures, and hence highly localised and enhanced fluid flow, can develop at intersections in fracture systems (McKenzie & Morgan, 1969; Andrews, 1989). Lithostatic pressure at depth in the Earth's crust will resist voids opening so that finite deformation is likely to be accommodated on a fractal array of faults and fractures around the intersection of faults and fractures (King, 1983; Andrews, 1989). This introduces further potential for fractures and aperture connectivity

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that must be assessed and taken into account and is only possible with the development of a well-constrained geological model.

Faults, therefore, generally have uneven rough surfaces and are associated with various rocks, resulting in the existence of small voids between the fragments and along which fluids may move. The fluids commonly precipitate (deposit) minerals (e.g. clay minerals, quartz or calcite) along the fault, which often leads to the cementation of the fault zone and closure of (or reduction in the size and connectivity of) the network of interconnected voids. Dependent upon the main mineral deposited along the fault plane, the cemented fault rock may be harder or softer than the enclosing unfaulted rock and thus be stronger or weaker respectively. Fault zones can, therefore, form fluid conduits if connected open fracture networks are present within a rock mass. The highest fluid flux potential will occur where and when fracture apertures, density and connectivity are greatest (Sibson, 1996; Cox et al., 2001). Alternatively, fault zones can form fluid barriers where the impermeable fault gouge forms during the shearing process (e.g. shale gouge, shale smear) or as a result of post deformational cementation (e.g. Knipe, 1992; Sibson, 1996).

The evolution of the fault and cement material can also be a complex process that occurs over considerable periods of geological time, with many fault zones showing evidence of more than one period of activity and cementation. It is known that some of the major basin-controlling faults in the UK have suffered repeated reactivation both in extension and compression (Chadwick, 1986, 1993; Chadwick & Evans, 2005). However, as described below, fault reactivation causing a direct rock rupture hazard at surface in these examples, or indeed any mapped fault at surface in the UK, is considered extremely unlikely: there is no evidence of any such faults having been active during historic times in the UK (see below).

From the above, it can be seen that fault zones will have varying degrees of porosity. This porosity, particularly at deeper levels, can be reduced by the circulation of fluids from which minerals are precipitated through processes such as seismic pumping (e.g. Sibson et al., 1975; Sibson, 1992). Alternatively, the presence of hydrocarbons in the system may help to maintain structural porosity and permeability (open fracture apertures) by restricting concentrations of hydrothermal fluids in the localised fracture system and thereby reducing the potential for mineral precipitation and fracture blockage to occur (Gartrell et al., 2004). Experiments have also shown that, in the absence of cementation, faults and fractures are very difficult to close to fluids due to natural fracture surface roughness (Gutierrez et al., 2000). In addition, partial filling of fractures by mineral cements can actually act to maintain structural permeability by holding open the fractures (e.g. Stowell et al., 2001; Gartrell et al., 2004). Fluid focussing at the fault intersection may also contribute to increased pore pressures in the fracture zone, which may enhance fracture activity.

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6.1.2 Sealing or non sealing ('leaky') faults?

When faults undergo displacement, they change the rock volume and their own fluid transmissibility properties by:

- juxtaposing varying lithologies (and lithological properties) across the fault
- smearing impermeable/semi-impermeable fault rocks in the fault zones
- cataclastic grain-size reduction resulting from abrasion during deformation
- the development of a damage zone of smaller (sub seismic resolution) faults adjacent to the main fault which may or may not have additional, associated sealing properties
- 'seismic pumping' of diagenetic fluids and hydrocarbons through the system

The sealing capacity along a fault is not constant and leakage of hydrocarbons across a fault occurs when the buoyancy pressure exceeds the capillary entry pressure of the fault. This is not

necessarily confined to the crest of the structure or even to where the SGR value is lowest (Bretan et al., 2003). Generally, the relative cross-fault juxtaposition of potential reservoir and non-reservoir units across the fault determines fault-seal potential (e.g. Clarke et al., 2005a&b). A schematic illustration (Fig. 16) shows a cross-section of potential hydrocarbon traps (fault-blocks) resulting from normal faults that offset a sand-shale sequence. For traps represented by fault blocks and especially hangingwall traps, such as the left hand fault-block (Fig. 16), there is generally the requirement that hydrocarbons are sealed by faults against the neighbouring fault compartment (footwall block). Fault seal can arise from reservoir-non reservoir juxtaposition or development of fault rocks having high entry pressure between reservoir rocks. Potential hydrocarbon accumulations and sealing situations are classified into two main groups based on fault throw related to reservoir thickness (Fig. 16; Færseth, 2006):

- Self-separated, in which the reservoir is entirely separated from its continuation across the fault. If the reservoir is juxtaposed against shale across a fault, it results in a juxtaposition seal, which is likely to prevent leakage. If a fault juxtaposes reservoir A against reservoir B, a membrane seal along the fault is required to prevent leakage of hydrocarbons across the fault. In a fault rock, a membrane seal is a fault rock with high entry pressure (Watts, 1987b) developed as a result of shale smear, cementation or cataclasis.
- Self-juxtaposed, in which the reservoir is partially juxtaposed against itself across the fault and in which to prevent leakage, a membrane seal along the sand-sand juxtaposition is required. Reduced permeability across the fault may result from mechanical shearing with grain reorganization, grain size reduction, denser grain packing and diagenetic reactions as well as phyllosilicate smearing (e.g. Fisher & Knipe, 2001). Where a shale layer is offset by a fault with throw greater than the vertical thickness of the layer, a shale smear may be entrained into the fault zone (section 6.1.2.1). The shale that is situated stratigraphically between reservoir A and reservoir B represents a source layer with the potential to develop a smear along faults that cut the sedimentary sequence. If the smear forms a continuous and impermeable membrane, the smear can separate the two reservoir units in the footwall and hanging wall blocks that have been juxtaposed (Fig. 16 inset) and that, in the absence of shale smear, would be expected to be hydraulically connected across the fault surface.

Initially an analysis of the lithological juxtapositions (or the petrophysical properties of the lithologies) across a fault surface can be used to determine sealing capacity to cross-fault migration resulting from fault-block juxtaposition alone. However, a complex fault zone will have exhibited varying transmissibility values in three dimensions which will have changed with displacement through time. The understanding of fault seal generation is crucial, therefore, to the assessment of the migration and trapping of hydrocarbons and thus the role of faults in gas storage. The effectiveness of the seal depends upon the porosity and permeability characteristics of the fault zone, which are controlled by the microfabrics present, themselves controlled by a range of processes. Three broad classes of seal may be recognised (Knipe, 1992):

- collapse seals, where the permeability/porosity of the fault zone is reduced by pore volume decrease achieved by grain reorganisation produced by fracturing, grain deformation and dissolution and by grain boundary sliding
- cement seals, where the reduced flow across a fault is achieved by the precipitation of cementing minerals in and adjacent to the fault
- juxtaposition seals, generated by the coming together of lithologies with different sealing capacities. Juxtaposition relationships are inferred from the fault plane profiles. The nature of the fault gouge or fault rock developed is an important factor in controlling fault sealing capacity. This is partly assessed by quantitative fault seal analysis, which estimates the sand/shale composition of the gouge and empirically relates seal and gouge composition: sand-rich gouges tend to leak, shale-rich gouges tend to seal. As in the

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scenario of caprocks (section 3.4), the entry pressures of the fault gouge and fault zone determine the effective sealing potential of the fault (membrane seal – see below).

6.1.2.1 FAULT ZONE PROCESSES – DEVELOPMENT OF SHALE GOUGE (SHALE GOUGE RATIOS; SGR)

As previously mentioned, there are many examples of faulted, hydrocarbon-bearing, sedimentary basins in which faults can seal hydrocarbons even in the presence of juxtaposed reservoir units. In these cases, fault seal is the result of one or a number of geological processes that operate within the fault zone (Clarke et al., 2005a&b).

Faulting of a major shale unit may also lead to argillaceous (shale) smearing to the development of 'shale smear'. During faulting, shale deforms in a rather more ductile manner, being drawn out (and recrystallising) along the fault leading to the entrainment of clay-rich lithologies into the fault zone. This contributes to the development of a low permeability fault gouge that can act as a barrier to fluid flow, preventing leakage of hydrocarbons across or along faults (Fig 16). It is the primary example of a fault-zone process that contributes to fault-seal potential. Were normal faults offset sand-shale sequences, shale smear along faults is commonly invoked in hydrocarbon exploration as a likely membrane seal, assumed to prevent leakage across large faults and thereby to seal potential traps. This clearly occurs in many North Sea fields. It is also known that rock types other than shale, such as coal, siltstones and carbonates, may smear and thereby contribute to the development of a low permeability fault gouge (Færseth, 2006).

The importance of shale smear and its particular relevance to mixed arenaceous and argillaceous sequences that are generally found in hydrocarbon fields has meant that the process has attracted considerable research and attempts at numerical quantification. Factors that govern the development of an argillaceous smear within the fault zone are:

- the quantity, mineralogy and distribution of argillaceous source units within the faulted sequence
- the thicknesses of these argillaceous source units
- the throw on the fault

With these input parameters and the dynamics of smear emplacement, numerous numerical models have been developed to quantify the quality of a resultant seal in terms of a dimensionless number that, when calibrated with appropriate analogue examples, can be used to express the likely sealing capacity of a fault cutting a sequence of known lithology. Of these numerical models, the *Shale Gouge Ratio* or SGR (Freeman et al., 1998; Fristad et al., 1997) is commonly employed for the analysis of fault seal (e.g. Freeman et al., 1998; Bretan et al., 2003). It is a measure of the proportion of argillaceous material within the fault zone and can be used to predict the height of hydrocarbon columns retained by the faulit seal.

The prediction of smear continuity and the sealing capacity of the smear (SGR) is, therefore, of fundamental importance in assessing the prospectivity of hydrocarbon traps and the gas tightness of the trapping structure for gas storage. It is of vital importance when assessing the maximum hydrocarbon column height that can be supported by faults (i.e. the fault seal capacity) and thereby the size of the trap or effectiveness for gas storage purposes involving repressurisation of the reservoir and seals. It is now common place practise in the oil industry, using juxtaposition relationships and varying argillaceous smear and cataclasis in three-dimensional space, to build fault-zone models in oilfields that calculate, model and visualise fault-seal properties through time within a complex, three-dimensional fault setting. The resulting models can be combined with invasion percolation-driven flow-pathway modelling techniques to analyse the three-dimensional models for possible fault-controlled hydrocarbon accumulations and migration pathways (see e.g. Freeman et al., 1998; Clarke et al., 2005a&b).

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6.1.3 Fault related leakage and hydrocarbon anomolies

Although many examples exist of faults being impermeable and providing seals in oil and gassfields, there are examples where faults appear to be permeable and nonsealing. A number of studies describe hydrocarbon concentrations increasing near faults (e.g. Fisher & Stevenson, 1973; Voytov et al., 1972; Reitsema et al., 1978; Abrams, 1992). Abrams (1992) described shallow cores from the Bering Sea that showed hydrocarbon concentrations within 75 m of a known fault and increasing towards the fault, due to passive hydrocarbon seepage. Studies in the Gulf of Mexico detected macroseepage up to several hundred metres away from fault scarps. This may have been partially due to leaky superficial and unconsolidated near surface sediments, a fracture system or sub seismic scale faulting that was undetected by high resolution seismic reflection profiles (Abrams, 1996).

Studies of the Pyrenees-Macedon fields in the Northern Carnarvon Basin, Australia reveal seismic amplitude anomalies and gas shows above the reservoir, indicating vertical leakage from the trap (Bailey et al., 2006). The studies also reveal the differing roles that faults can play and the need to characterise and model their performances effectively. Hydrodynamic analysis of pressure data indicate that faults separating the fields act as barriers to the migration of hydrocarbons and water, whilst faults within the Macedon Field do not. The reasons for hydrocarbon leakage and the difference in fault seal capacities are investigated using a number of approaches and analytical techniques. These include integrating field observations, analysis of pressure and stress data, the appraisal of caprock (standard mercury porosimetry measurements) and fault (SGR) membrane seal capacities, constraining geomechanical properties (top and fault seals) and wellbore-based fracture analysis. It has been found that the caprock seals are at a low risk of capillary failure, but vertical leakage is possible via dynamic failure along pre-existing faults and conductive fractures. Lateral leakage across the reservoir into different fault blocks is thought to arise by fault juxtapositions of porous reservoir rock types (so called 'thief zone fault juxtapositions'). The difference in observed fault seal capacities between different faults is explained by a combination of the spatial distributions of SGR and buoyancy pressure.

There are also the recent studies of the Ketzin former aquifer gas storage site to the west of Berlin, where a gas chimney and amplitude anomalies are noted on seismic reflection data above a graben bounding fault. These features illustrate that gas has leaked to shallower levels via the fault (Juhlin et al., 2007 – Appendix 5).

6.1.4 Strain rates, deformation and faulting in and around halite beds

It is important to assess the possibility of faulting in halite and associated non salt interbeds that might be used for gas storage. Section 4.2.1 outlined the rheological behaviour of halite, illustrating that deformation of halite is commonly viscoplastic in nature with many people's perception being that it 'flows'. In actual fact it is not flow per se, but is described as creep achieved through crystal plastic deformation and/or pressure solution mechanisms (e.g. Jenyon, 1986a,b&c). Some studies have, however, suggested that long-range methane gas migration occurs through fractures in salt in the Algarve Basin, Portugal (Terrinha et al., 1994) and in the Sergipe-Alagoas Basin, NE Brazil. In the latter, faults are recorded in Aptian (early Cretaceous) age halite and sylvanite from the Petromisa Mine near Aracaju. The salt lies at a present depth of around 300 m, being overlain by Cretaceous strata. Coarse-grained halite has recrystallised along the fault plane and open fractures, filled with methane, are present in the mine (Davison, et al., 1996a). As stated previously (section 4.3), these studies should perhaps be urgently reviewed as they may indicate problems of tightness not previously recognised or that might not necessarily be anticipated.

Many examples exist of the interpretation of seismic reflection data that show faulting affecting only the top or base of a halite dominated succession; the faults apparently not having propagated through the halite body to displace the other enclosing boundary. The salt beds form a weak layer between the more competent (and harder) rocks and act as a detachment

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(décollement) surface into which faults sole or die out. The salt is interpreted to have deformed in a ductile or plastic manner, effectively having 'absorbed' the faulting and isolating the deformation between the layers (e.g. Jenyon, 1986a&b; Stewart et al., 1996; Harvey & Stewart, 1998; Chadwick & Evans, 2005). This gives rise to an array of differing structures in the overburden such as rafts and 'turtle structures' (e.g. Vendeville & Jackson, 1992).

The Boulby Halite in the Teesside area is affected by the E-W trending and northerly downthrown Saltholme Fault and illustrates this situation. Displacement on the fault is about 50 m at the base of the halite, but there is little effect on the strata overlying the halite (Phillips in Smith, 1996). The changes in thickness and the textures of the halite in the vicinity (section 6.1.4.1) have been attributed to ductile flow of the halite as it absorbed most or all of the displacement of the Saltholme Fault (Smith, 1996). Similarly attributed to absorption of fault movements by the halite beds in the same area are the thickness variations in the halite in association with a steep reverse fault extending up from the underlying Seaham Formation into the Boulby Halite and dying out, and farther afield in the southern North Sea, strike slip faults deforming the base of the halite but not overlying strata (Woods, 1979; Jenyon, 1990).

The process of halite beds undergoing ductile deformation at a rate that readily kept pace with and absorbed (brittle) the faulting and graben formation that occurred in overlying sequences has been demonstrated in a study of well-preserved fault arrays in Canyonlands National Park, Utah (Moore & Schultz, 1999). Accumulated extensional strain across the closely spaced normal fault arrays has been calculated at rates of approximately 1.5 to 2 cm/yr (or 10^{-14} to 10^{-13} s^{-1}). The authors suggested these rates are significantly below the rates of salt flow of >200 cm/yr (strain rates of 10^{-11} to 10^{-9} s^{-1}) derived from salt glaciers (Talbot & Rogers, 1980; Talbot & Jarvis, 1984; Jackson et al., 1994). This they interpreted to indicate that salt flow and formation of reactive salt diapirs at depth beneath the grabens has accommodated the accumulated displacement and strain rates of the brittle faults (Moore & Schultz, 1999). The interpretation would appear to be supported by the strain rates for in-situ deformation of salt, which vary by over eight orders of magnitude from 10^{-8} s^{-1} to 10^{-16} s^{-1} (Jackson & Talbot, 1986). The more rapid rates are those of borehole and mine closures, the lower rates being typical of rates associated with diapiric growth (Anderson & Browns, 1992).

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However, although commonly perceived as deforming plastically halite may suffer microfracturing (e.g. Munson et al., 1999 – section 2.2.7.3.2.1) and undergo brittle fracture and faulting under certain conditions (e.g. Davison et al., 1996a). Brittle failure of salt is reported in the Boulby Halite (Teesside; Smith, 1996 – section 6.1.4.2) and in the exposed top of a diapiric salt ridge in NW Yemen (Davison et al., 1996b).

The most likely instances when brittle failure might occur would be when the rock salt is:

- Exposed to high strain rates (Davison et al., 1996a), coupled with shallow depths (i.e. conditions of lower temperatures and confining pressures. This would appear to be the case in NW Yemen where the top of the salt diapir/ridge has broken surface and the salt has deformed under near-surface temperatures and pressures, which are considerably lower than at depths being considered at gas storage facility sites.
- Suffers rapid loss of confining pressures - for example during cavern formation, if cavern pressures are not kept high enough, the cavern walls will, as a result of horizontal stresses, develop microfractures weakening the halite which then suffers breakouts (spalling). In extreme cases, this might perhaps lead to the sudden release of confining pressure on a fault in the overlying strata that might propagate rapidly into the halite beds.
- When the salt beds are relatively thin and/or the faults define a major basin or intrabasinal structure
- Where the salt crystals containing impurities or inclusions lead to strain hardening and rupture of the salt

- Where the halite beds are thin and interlayered with mudstone or anhydrite beds

There may be other scenarios in which brittle failure could occur, but the ones detailed above are those most likely to lead to the rock salt suffering increased local stresses, strain hardening and ultimately to fracture and the propagation of a fault through the salt layer. The thinner the salt bed then the greater also the potential for this to occur.

Following the propagation and displacement on the fault, the rock salt, being viscoplastic, will over geological time and under normal lithostatic pressures undergo crystal plastic deformation and creep. The salt will effectively self-heal (anneal) and 'repair' any areas of fault damage. This will be driven by the natural tendancy to lower the (strain) energy held in the deformed salt crystals/grains, facilitated by the increased temperatures and pressures that accompany burial of salt beneath an overburden.

It is important to understand, therefore, that a fault possibly having connected through the salt bed(s) and having caused damage (fracturing) to the salt, may well, over geological time, have subsequently been 'repaired' by the naturally occurring creep of the salt.

6.1.4.1 Linear fabric and gneissic foliations within halite beds

At the Preesall Inquiry much was made of a strongly lineated and foliated schistose/gneissic (?mylonitic) fabric found at certain intervals of the Preesall Halite in the fully cored Arm Hill borehole. It was observed on broken core surfaces (Fig. 10c) and was claimed by opposition groups to be slickensides resulting from faulting of the halite and such zones were thus considered a route for gas migration. A significant point is that slickenside structures can originate in processes other than during faulting, incuding during sedimentation. They are thus not diagnostic of brittle fault movements (Evans et al., 2005).

As described above, faults in salt exposed near the top of a salt diapir in NW Yemen have been noted and on which slickensides have had described within the salt. This has ocurred at shallow, near-surface levels and not at depths of 300-350 m or more, as at Preesall. Close inspection of the fabric in the Preesall Halite shows it to be elongate, flattened and subparallel halite crystals, giving an undulose schistose or gneissic (mylonitic) fabric and surface break to the core. The fabric is found in thin zones within more massive halite and an alternative interpretation was put forward by the Appellant. This was that the fabric might be unrelated to brittle processes, but represent fabrics arising from ductile flow of the halite, perhaps related to deformation of thin non-mudstone interbeds (Evans, 2005).

Smith (1996) described a fabric very similar to that noted in the Preesall Halite from cores of the Boulby Halite in a great number of boreholes on Teesside (Fig. 10b). There the fabric was found forming sheets ranging from a few millimetres to 3.8 m in thickness, which give rise to anastomosing networks around less deformed halite 'pods'. They were interpreted as the flow lineated sheets, which were also closely associated with breccias of anhydrite. Both fabrics were interpreted as the result of ductile flow of the halite due to differential extension within the halite body and which acted as 'glide planes' (Smith, 1996). The precise mechanism by which the flow-lineated sheets in the Boulby Halite evolved is as yet unclear, but it seems likely that intracrystalline slip (dislocation creep) and pressure solution producing fluid films along crystal boundaries that was then reprecipitated were involved (Smith, 1996). The flow of the halite was probably driven by pressure gradients (Talbot et al, 1982; Smith, 1996).

Thin mylonitic zones (< 5 cm thick), comprising similar strong shape preferred orientation and foliation formed by elongate crystals are described from within naturally deformed extrusive Eocene-Oligocene rocksalt in salt diapirs of the Eyvanekey plateau and Garmsar hills (Schléder & Urai, 2007). These mylonite microstructures indicate deformation mechanisms of both solution-precipitation creep and grain boundary sliding accompanied by solution-precipitation. These were generated during emplacement of the salt diapir at shallow levels under differential stresses between 1.4 and 2 MPa and strain rates of about 10^{-10} s^{-1} (Schléder & Urai, 2007).

Until further work can be carried out, it seems likely that the fabric observed in the Preesall Halite in the Arm Hill borehole, with an obvious similarity to the linear flow fabrics described from the Boulby Halite, has similar origins. The concentration of such sheets of flow both at or near the top and base of the Boulby Halite and the thicker anhydrite/dolomite interbeds, probably represents a response to the greater rigidity of the interbeds and their effects in focussing and transmitting pressure to the halite (Smith, 1996). As indicated, such a relationship was tentatively suggested for the Preesall Halite examples (Evans, 2005), but is worthy of further study should further consideration of the Preesall Halite for gas storage purposes be likely.

6.1.4.2 Fractures and faults in the Boulby Halite, Teesside

Fractures and faults are described in cores from the Boulby Halite at depths of approximately 390-425 m on Teesside (Smith, 1996). They are more readily identified when in close proximity to more competent and clearly fractured non-halite anhydrite and dolomitie interbeds (and salt with gneissic/schistose foliation) and as such, this appearance may be illusory (Smith, 1996). However, faults are present and their fault plane is observed. In addition to faults, the Boulby Halite in several of the cores contains pull-apart structures up to 100 mm across. There is, however, no evidence of any significant displacement on these structures.

The fractures and several of the faults contain, or are associated with, veins of colourless to amber granular and fibrous halite. Fibres in the latter are normally perpendicular to the walls of the veins. Some veins contain slightly curved fibres, indicating some movement of the walls of the veins during crystal growth. There is also evidence from the fibres of the episodic widening of some fractures and multiphase crystal growth (Smith, 1996).

6.2 UK SEISMICITY, SEISMOTECTONICS AND SEISMIC HAZARD

UGS facilities are planned in areas of the UK that have been subjected to shaking related to earthquakes that have occurred elsewhere in the UK, both on and offshore. It is appropriate, therefore, to provide a brief overview and assessment of UK earthquakes and from that, the potential danger from seismicity to UGS facilities in the UK. However, it emphasised that an overview of this type is insufficient and any assessment of seismic hazard will probably have to be done on a site-by-site basis.

Earthquakes occur due to movement on faults (planes of rupture in the earth's crust), releasing energy (seismicity). Although seismicity risk in the UK is not of the same order of magnitude as that in, for example, Japan and California that lie close to plate boundaries, the UK nevertheless has a low to moderate seismicity. It is sufficiently high to pose a potential hazard to sensitive structures such as dams, chemical plants and nuclear facilities (Musson, 1997, 2003a&b). Between 300 and 400 earthquakes are detected annually in the UK, with only about 10% of them strong enough to be felt by people (Browitt & Musson, 1993). Occasionally, larger earthquakes occur, such as the Welsh border earthquake in 1980 (magnitude 5.4) and the 2007 Folkestone earthquake (magnitude 4.3). The areas over which the larger earthquakes are felt are often very large, as with the Dogger Bank (7/6/31), Lleyn Penninsular (19/7/84) and Roermund (Netherlands) events (Fig. 17). British earthquakes are not, however, generally perceived as presenting a hazard to life: in the period for which reliable records are available (since around 1580), only 12 fatalities can be associated with earthquakes (Musson, 2003a).

In order to quantify the effects, earthquake hazard must be distinguished from earthquake risk. Hazard is taken to be the likelihood of shaking of a certain strength taking place. Risk is the likelihood of actual damage resulting, taking into account the distribution and strength of buildings etc. The level of hazard is dependent upon the size of the earthquakes, their distribution within the crust and over time. In Britain, earthquake depths range from 2-20 kilometres, with the typical British earthquake occurring at depths of between 5 and 15 km. An earthquake occurring near the surface will have much more impact than one many kilometres deep (Browitt

D2-253 (Cont.)

& Musson, 1993): earthquake waves are twice as powerful on the surface than further down (Booth, 2007), because as seismic waves approach the surface they slow, becoming amplified and more destructive. It is noteworthy that the most damaging earthquake in the last 400 years (22nd April 1884 at Colchester), was not very large (4.6 M_L), but was very shallow at about 2 kilometres (Browitt & Musson, 1993). As a consequence, underground structures stand up quite well because they are buried rather than on the surface, because as indicated above, seismic waves approach the surface they slow, becoming amplified and more destructive. Also surface waves (known as Rayleigh and Love waves) are generated by earthquakes, travelling along the earth's surface and have a greater effect on buildings.

Further information on the subject of seismicity and earthquake hazard and risk assessment in the UK is available on the BGS website (http://www.earthquakes.bgs.ac.uk/hazard/Hazard_UK.htm), in Musson in Evans et al. (2005) and the various papers of Musson quoted below and reference lists therein.

6.2.1 Measurement of the magnitude or strength of an earthquake

The spatial location of any earthquake can be considered in three dimensions. The hypocentre (or focus point) is the source location of the earthquake (i.e where the slipping of the rocks along the fault begins). The point at the surface and generally marked on a map is the epicentre and lies directly above the hypocentre. The vertical distance from the hypocentre to the epicentre is the depth of the earthquake.

The magnitude of an earthquake is generally measured or referred to in terms of the Richter Scale, which is a way of measuring the amount of energy released during an earthquake. The Richter magnitude scale (or more correctly, local magnitude M_L scale) is an attempt to give one value to the overall size of the earthquake. A single number is assigned to quantify the amount of seismic energy released by an earthquake. It is a base-10 logarithmic scale obtained by calculating the logarithm of the combined horizontal amplitude of the largest displacement of the waves from zero recorded on seismographs with adjustments included to compensate for the variation in the distance between the various seismographs and the epicentre of the earthquake. Measurements have no limits but because of the logarithmic basis of the scale, each whole number increase in magnitude represents a ten-fold increase in measured amplitude. In terms of energy, each whole number increase represents a 30-fold increase in energy release (and a 10-fold increase in the amplitude of ground displacement). Thus a magnitude 5 earthquake releases 30 times the energy of a magnitude 4 earthquake and 900 times the energy of a magnitude 3 earthquake (Musson, 1994).

The Modified Mercalli Scale is a subjective measure that describes how strong a shock was felt at a particular location in values ranging from I (not felt, except by very few under especially favourable conditions) to XII (damage total, lines of sight and level distorted, objects thrown upwards into the air).

It has long been realised that larger earthquakes occur less frequently than smaller earthquakes, the relationship being exponential, i.e. roughly ten times as many earthquakes larger than 4 M_L occur in a particular time period than do earthquakes larger than magnitude 5 M_L. This holds true for UK earthquakes. The following conclusions about average recurrence in the UK can be drawn (Musson, 2003b):

- an earthquake of 3.7 M_L or larger every 1 year
- an earthquake of 4.7 M_L or larger every 10 years
- an earthquake of 5.6 M_L or larger every 100 years.

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Increasingly, an estimate of the size of an earthquake at any particular point is expressed as the strength of shaking or intensity at a particular place and is based on a number of things that may be found in an everyday environment (the extent of damage to buildings of different type, the reaction of people affected etc.). In Europe these observations are then related to the European Macroseismic Scale (EMS: refer Grünthal et al., 1998; http://www.gfz-potsdam.de/pb5/pb53/projekt/ems/index.html), where 1 is not felt and 8 is very damaging.

A description of what happened is matched to the overall picture of the different descriptions in the scale as follows (further detail of the various grades and their meaning are given in Appendix 5):

- 3 - Felt by few
- 4 - Felt by many indoors, windows and doors rattle
- 5 - Felt by most indoors, small objects fall over
- 6 - People run out in alarm, slight damage to buildings (plaster cracks)
- 7 - Moderate damage to buildings (chimneys fall, cracks in walls)

The EMS-98 scale is one of a family of intensity scales that recognises the statistical nature of intensity, that is, that at any place a certain effect is likely to be observed in a proportion of cases only and whether that proportion is small or large is itself something that tells one about the strength of the shaking. Earlier scales often described only effects, with no quantities, implying that the same effect was universal on all such sensors when the intensity reached that value.

6.2.2 General background to seismicity in the UK

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The following sections, based upon Musson (2005a, in Evans et al., 2005), outlines the seismic hazard in the UK context. Each region or site area considered for UGS would probably require an individual probabilistic seismic hazard assessment (PSHA).

It is perhaps appropriate to start with some words about seismic hazard in the UK in general, as common misconceptions exist. These are due to some misunderstanding of seismicity in the UK context and the extent to which issues relevant to seismic hazard in seismically active plate margin areas such as California and Japan have created expectations concerning procedures. These procedures are not always appropriate in less seismically active intraplate areas of the world, such as that in which the UK lies.

In places like California, approaches to seismic hazard are largely directed to consideration of individual faults. For a given site, the questioning would typically be along the lines of:

- Is this fault, which is near a site, active
- If not, what is the closest active fault to a site
- Is a site best avoided because it lies so close to the trace of an active fault that surface displacement may occur across it in a future earthquake?

Conventional definitions, largely developed in active tectonic areas, refer to any fault that has demonstrably moved in the past x years as active, where x is some large number extending certainly beyond historical times, usually back to the beginning of the Quaternary (c. 1.8 Ma). It is common practice to examine known faults one by one, compare them to this definition, and decide if they are active or not. The number that meets this criterion indicates the number of "active faults".

By contrast, in the UK, which lies in a tectonically quiet intraplate setting and which has not suffered a surface rupturing fault during at least historical times, the concept of an "active fault" is unhelpful and probably inappropriate altogether (Musson, 2005a&b). In order to estimate the

number of "active faults" as defined above, the problem can be approached from the opposite direction. All earthquakes occur on faults and in mainland UK there are approximately 300-400 distinct epicentres. Therefore, there must be about this number of active faults in the UK, even though most cannot actually be recognised in the field. The distribution of faults at 5-15 km depth is generally poorly known because maps of faults occurring at the Earth's surface are of limited use for precisely locating faults at depth.

In the case of major earthquakes worldwide, causative faults can be identified in one of a number of ways. In the first case, since major earthquakes require large structures to host them, the fault may already be well known. In the second case, the fault may be directly observable through surface rupture. Thirdly, the fault plane is often imaged by the distribution of aftershocks. Fourthly, waveform inversion can be applied to map not only the fault itself, but the distribution of rupture along it.

These methods are of limited application in the UK. It is impossible to not only identify any demonstrably active faults, but it is also extremely difficult to discern any relationship between the pattern of seismicity and local or regional geological structure. It has, to date, proved extremely difficult to reliably associate any British earthquakes with specific known faults. Even the two largest U.K. faults, suspected to be active, pose problems in attributing historical seismicity to them as distinct features. The typical British earthquake is small and occurs at depths of between 5 and 15 km and a typical damaging earthquake in the past has been around 5 M_L (M_L = local or "Richter" magnitude) in magnitude (no onshore event is known to have exceeded 5.4 M_L). Since the typical earthquake is small, its rupture dimensions are also small and what faulting occurs at these depths is usually poorly known. The hypocentre is likely to be located only to an accuracy of ± 5 km or so in three dimensions and within this crustal volume several faults may occur. Hence, looking at a map of faults that shows only their surface traces is of very limited use.

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Consequently, it is thought very few British earthquakes have reliable fault attributions. Notable exceptions might be the 15 February 1865 Barrow earthquake(Musson, 1998), the 16 September 1985 Ardentinny earthquake (Redmayne & Musson, 1987) and the 22 September 2002 Dudley earthquake (Baptie et al., 2005). These three appear to be cases where named faults can be cited as causative features with some certainty. A few others exist, but not many.

This is typically the case in intraplate areas, due to the absence of significant tectonic deformation. At plate boundaries and other areas of active deformation, large-scale differential movement within the crust requires fault planes on which to accommodate this movement. Most large faults were originally created in this way. The rocks that comprise the British Isles have been subjected to various phases of orogenesis and active deformation in the past, leaving behind many fault structures which were once active but are now relict features. It is possible, however, that these faults could be reactivated in the context of the quite different tectonic circumstances that exist today.

6.2.3 Hazard from ground rupture and hazard assessment in the UK

The issue of hazard from ground rupture in the UK does not really arise. This is demonstrated in Figure 18, which shows all earthquakes > 3 M_L with known depths in mainland UK and the Irish Sea, plotted by latitude and depth as a north-south cross section. The vertical bars show the extent of the fault rupture calculated from Wells & Coppersmith (1994), assuming that all ruptures are circular and that rupture length is the predicted value plus one standard deviation. None of the ruptures intersect the surface and very few even come close and this is with what can be considered a pessimistic model; Burton & Marrow (1989) predict much smaller ruptures for the same size of earthquake in Britain than are given by Wells & Coppersmith's (1994) global regressions, which are primarily based on large magnitude earthquakes.

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Not only are British earthquakes generally small, therefore, but the larger, more infrequent, events tend to be of deeper focus. This is illustrated in Figure 18, and is even clearer in Figure 19, which plots magnitude against depth for a slightly larger area than is covered in Figure 18. Only two events in the last 400 years are identified that are both >4 ML and have depths in the top 5 km of crust.

As mentioned above, the typical damaging British earthquake in the past has been around 5 M_L and such an earthquake requires movement on a fault no more than a few kilometres long. An earthquake of around 5.8 M_L, similar to the 1992 Roermond earthquake in the southern Netherlands and which might be considered the typical scenario event for the UK (Musson, 2004a) can, from the relations of Wells & Coppersmith (1994), originate from 6 km of fault rupture. Faults large enough to host such an earthquake are rather common in the UK. Major fault structures are not required.

6.2.4 UK seismotectonics

A major report for Nuclear Electric (Chadwick et al., 1996) presented detailed maps of the deep subsurface structure of the UK and a seismotectonic model for the UK. The research indicated that the UK is divided into a set of generalised 'seismotectonic zones'. Each of these zones has characteristic crustal structure and each is associated with seismicity, which at least in part, is explicable, although the correlation of deep structure with seismicity is not clear-cut. From this it is possible to make an assessment of both local source zones and also the probable hazard from individual faults that might be identified as relevant to site-specific studies.

Any correlation of individual bulk crustal properties (thickness, depth, heatflow etc.) with seismicity is too weak to be recognised and therefore, taken in isolation, bulk crustal properties do not appear to exert a strong seismotectonic influence in the current stress regime. However, major faults affecting the crust do appear to be of greater seismotectonic significance and show more obvious correlations with seismicity.

D2-253 (Cont.)

Major faults form important lines of weakness in the upper crust, very effectively taking up strain during crustal extension or shortening. In the UK context, on geological timescales the relatively low-angle thrust-faults have been of particular importance in this respect, having suffered compressional and extensional reactivations at various times in the past. These structures have controlled the location and development of sedimentary basins, many containing the oil and gasfields or halite beds being considered for gas storage purposes (refer Chadwick, 1986, 1993; Chadwick & Evans, 2006). However, the observed correlation of present seismicity with these features is by no means as clear-cut as might be expected. In the current regime representing rather low stress (calculated from *in situ* stress measurements in boreholes; Chadwick et al., 1996), cumulative accrual of strain appears to be very small, and such strain that does occur is not being strongly localised around or along these pre-existing zones of weakness.

The maximum horizontal compressive stress is oriented roughly NW-SE, which is probably attributable to 'ridge-push' from the North Atlantic mid-ocean ridge (Whittaker et al., 1989; Zoback, 1992). Earthquake focal mechanisms are thus dominantly strike-slip on near-vertical faults, indicating that, at seismogenic depths, the intermediate principal stress is vertical. Faults oriented north-south or east-west are most favourable to being reactivated under these conditions and might be considered as capable of reactivation. This applies not only to mapped faults with a surface expression, but also (really, even more so) to basement faults, which may have no surface expression.

However, the orientation of the orientation of the stress field and the observed lack of deformation in the sedimentary cover rocks over the last 10 million years or so, suggests that under the current stress regime, horizontal stress magnitudes are low and unable to readily (or effectively) reactivate and drive either thrust faults or normal faults. This contrasts markedly

with the situation 20-10 Ma ago. At that time much stronger compressive stresses existed, which were the result of Alpine continental collisions and these were sufficient to drive major fault reversals with basin shortening and structural inversion. This is revealed by important compressional structures in the Weald and Wessex basin areas of southern England (refer Chadwick, 1993; Chadwick & Evans, 2006).

The effects of post-glacial isostatic rebound may exert localised influences on seismicity, particularly in the northern UK, but are not considered to be a driving force of regional significance.

Most UK earthquakes, therefore, appear to arise as a consequence of minor interactions and adjustments ('jostling') between upper crustal blocks, giving predominantly strike-slip focal mechanisms. Some systematic correlations of seismicity with deep structure can be recognised. Earthquakes are associated with steep transcurrent faults and in a general way with major thrust-faults, which appear to be reactivated to some degree. Enhanced seismicity is associated with the apical areas between converging faults and in particular, with the intersections of major faults (where three or more upper crustal blocks interact).

The seismotectonic model for the UK shows the country to be divided into a set of generalised 'seismotectonic zones' (Fig. 20), and indicates that in the southern UK, seismicity is associated with distributed, dominantly strike-slip, reactivations of Variscan and Caledonian thrusts and other basement faults. Interactions between the Midlands Microcraton and surrounding adjacent structural blocks appear to be a cause of significant seismicity, with, in particular, the northward transmission of stress (and strain) along the Pennine Line, the effects penetrating well into southern Scotland. In northern Britain, seismicity appears to be mostly restricted to the major northeast-trending structures such as the Great Glen and Highland Boundary faults and, in particular, their intersections with the Moine Thrust.

D2-253 (Cont.)

6.2.5 UK seismic hazard

Certain seismotectonic zones of low seismicity may well remain low in activity. Other low seismicity zones, such as those in northern Scotland, northeast England, and, particularly, central southern England, have the capability to become more active. High seismicity zones of regional extent are likely to remain active at similar levels of seismicity. Some more restricted high seismicity areas, particularly those associated with a specific fault structure (such as around the Lleyn Peninsula) may become less active as strain is partitioned to other segments of the fault structure.

This is relevant to seismic hazard in different ways. At the most obvious level, it is clear that seismic hazard studies concerned with long exposure periods (such as those connected with nuclear waste repositories), will be acutely concerned with identifying areas not active now but which have an enhanced possibility of becoming active within the lifetime of the facility.

But even for seismic hazard studies for short-term hazard (i.e. for exposure times of 50-100 years) it may be considered that should such areas co-incide with likely areas of UGS applications, then they might merit special treatment. The timescale on which possible changes in seismicity could occur in the present stress field is most uncertain, but could range as low as a few tens of years, or within the lifespan of the average engineering facility (Chadwick et al., 1996). Of course, quantifying the probability of current low seismicity areas becoming enhanced is difficult and subjective. However, as long as the aim is for a reasonably conservative approach to seismic hazard evaluation, identifying the possible areas of concern is a priority. It could also be argued that the possibility of a "maverick" earthquake, i.e. a relatively large earthquake occurring unexpectedly in a low seismicity area, should be considered to be higher in an area identified as having a higher seismic capability than in one identified as fundamentally stable.

A map of earthquakes in the UK, taken from the BGS catalogue (Fig. 20a) illustrates that the spatial distribution of earthquakes is neither uniform nor random, nor is there a clear-cut correlation of deep structure with seismicity (Chadwick et al., 1996; Musson, 2003b).

As might be expected for Britain, the areas of highest hazard parallel the areas where earthquakes have been most common in the past (Fig. 20), but particularly those places where repeated earthquake activity has been highly localised - this localisation has a pronounced effect on the hazard calculations compared to areas where the seismicity, while high, is more diffuse and less repetitive. The zones where hazard is higher than average encompass the W Highlands of Scotland, an arc shaped zone running from Carlisle to Pembroke, NW Wales and W Cornwall. The places in the UK with lowest seismic hazard are Northern Ireland (especially the western counties) and outlying parts of Scotland, including the Orkneys and Outer Hebrides.

The actual values of hazard are not particularly high, since the predicted intensity for the higher zones is only 6 EMS (Musson, 2003b). In other words, even in areas of relatively high exposure to earthquakes in the UK, if a facility has a life of 50 years there is only a 10% chance that it will experience shaking equivalent to intensity 6. Moving briefly from hazard to risk, taking a guideline that probably less than 5% of buildings of normal construction (e.g. conventional brick houses) will be damaged in a place when the intensity there is 6, the probability of damage for a single house in 50 years is therefore less than 0.5% (Musson, 2003b).

In Scotland most earthquakes are concentrated on the west coast, between Ullapool and Dunoon, with the addition of centres of activity near the Great Glen at Inverness and Glen Spean, and a small area around Comrie, Perthshire, extending south to Stirling and Glasgow. The Outer Hebrides, the extreme north and most of the east of Scotland are virtually devoid of earthquakes. For the north-west of Scotland the absence of early written records, the small population, and the recent lack of recording instruments means that there may be a data gap; for instance, there are indications that an earthquake occurred in 1925, possibly near Ullapool, with magnitude probably about 3.5 M_L, for which there are no first-hand reports. However, many other parts of Scotland, especially south of the Highland line, are quite well documented, at least since 1600, and therefore the lack of earthquakes is genuine.

D2-253 (Cont.)

Further south a similar irregularity is seen. An area drawn from Penzance to Holyhead, to Carlisle and then to Doncaster includes most English and Welsh earthquakes. The northeast of England appears to be very quiet, almost aseismic. The southeast has a higher rate of activity, with a number of earthquakes that seem to be "one-off" occurrences. The most notable example of these is the 1884 Colchester earthquake, a magnitude 4.6 M_L event which was the most damaging British earthquake in at least the last 400 years, and yet which occurred in an area (Essex) otherwise more or less devoid of earthquakes from the earliest historical period up to the present day. There are also important centres of activity near Chichester and Dover. The former produced a swarm-like series of small, high-intensity earthquakes in the 1830s, was active again in 1963 and 1970. The latter is close to the recent Folkestone earthquake on 28th April 2007.

The Lake District Boundary Fault Zone (LDBFZ) is a complex feature on the western boundary of the Lake District, oriented mostly NNW-SSE. In its northern regions it is an anastamosing (braided and branching) structure, with one of its splays in the Furness peninsula, the Yarlside Fault, almost certainly the fault responsible for the small but damaging 1865 Barrow earthquake (Musson, 2005a). It is because this earthquake was small and very shallow (perhaps 1-2 km) that this association can be advanced with some confidence (Musson, 1998). Another small, shallow earthquake, the 17 November 1755 Whitehaven earthquake, occurred within the traces of the LDBFZ and must have been related to it. The much larger 11 August 1786 earthquake (5.0 ML), which had an epicentre offshore from Whitehaven, may also have been linked to the LDBFZ.

It has been suggested (Akhurst et al., 1998) that the Preesall Fault and the Formby Point Fault to the south may be structurally related to the (LDBFZ). Thus, given that the LDBFZ has been seismogenic (i.e. responsible for an earthquake - which is different from saying that it is "active"

in the sense that, say, the San Andreas Fault is active), it is possible that reactivation could in theory shift to one of the southern splays at some point in the future, but there is no evidence that this has taken place.

Offshore, there is significant activity in the English Channel (the likely source of the Folkestone earthquake) and off the coast of Humberside. Because only the larger events in these places are likely to be felt onshore, the catalogue in the pre-instrumented period is probably under-representative of the true rate of earthquake activity in these zones.

6.2.6 Summary

Seismic hazard assessment in the UK tends not to be a search for the nearest active fault, but proceeds on the basis that a damaging earthquake can effectively happen anywhere. However, based on historical experience, it is clear that some parts of the country are more prone than others. The geological reason for this variation is not very clear (Musson, 1996), but it is statistically certain that the distribution of earthquake epicentres across the UK is not random or even (Musson, 2000). Normal hazard assessment procedure is to take account of these regional variations to construct a probabilistic model of earthquake occurrence that can be used to assess the likelihood of any degree of ground shaking within a specified interval of time (Musson, 2004b; Musson & Winter, 1997).

In quantifying the level of hazard by conventional probabilistic methodology, however, some problems arise in attempting to interpret earthquake data in terms of geological structure and faults. As indicated above, in the U.K., not only is it impossible to identify any demonstrably active faults but it is also extremely difficult to discern any relationship between the pattern of seismicity and local or regional geological structure. It is suggested that, in intraplate areas such as the U.K., it is often inappropriate to attempt to model individual fault sources. There is no proof that any particular faults in the UK are active. Because an earthquake of moderate size can occur on a very short fault segment, it is impractical to restrict fault modelling to major features.

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The UK, therefore, is seen as having low-moderate seismicity, with low levels of seismic hazard and risk, only really representing a problem for near surface and surface installations. Earthquakes in the UK are generally deep, typically occurring at depths of between 5 and 15 km and attributing any particular fault with an earthquake is extremely difficult, with only a handful thought likely to be seismogenic. The depth of UK earthquakes and the attenuation of seismic waves not just with distance from the epicentre but also depth means that the integrity of the structure deep under ground may not be affected, but that effects on surface and near surface infrastructure require to be taken into account. Deep underground facilities (the deepest currently anticipated being 2234 m in a depleted oil/gasfield and 2.1-2.3 km in a salt sequence – refer Table 1) are less than the typical depth of UK earthquakes. Deep facilities (more than a few tens to hundreds of metres) are, therefore, only at risk when they are actually cut by an active fault, which in the UK context with the history of seismicity relative to likely areas of gas storage, is considered unlikely

It has to be borne in mind, however, that low probability events do happen, for example, the Maharashtra earthquake of 1993 (Musson, 2003b). Assessing the hazard in this part of India in 1992, would have led to the conclusion that the probability of a damaging earthquake was extremely low. This would have been correct at that time, but unfortunately the following year the earthquake happened despite the very small probability. Seismic hazard assessment helps the engineer design safe facilities, but to be 100% safe would require designing every building against improbably large earthquakes occurring unexpectedly close to any given site almost irrespective of whether it were in a high activity zone or not.

In the UK, therefore, where sizeable earthquakes are historically rare, it may not be possible at this stage to quantify the probability of seismic hazards in any meaningful way. It may be more appropriate to deal with seismicity on a "what if" basis, where the consideration is "what would

happen if an earthquake of greater than a certain size were to occur". Then, if the facility has been designed properly, illustrate that the consequences for safety would be insignificant, or at least manageable. It is possible to design surface and near-surface facilities to be able to withstand seismic hazards. Such design and construction is now undertaken for nuclear facilities in areas of high seismicity such as Japan, where no leaks of radiation have occurred as a result of earthquakes. In addition, Japan has an operational UGS facility at the depleted Sekihara gas field a few kilometres north of Minami-Nagaoka (Oshita, 2002) and is also constructing underground LPG storage facilities facilities (Takeshi et al., 2000; Yamamoto & Pruess, 2004). The main problems are caused by the collapse of structures that are not designed with earthquakes in mind. Examples of this in the UK were the damage seen at Colchester in 1884 and more recently the toppling of chimney pots in the 2007 Folkestone earthquake.

Each proposal to develop a UGS facility may, therefore, have to be dealt with on a site-by-site basis and it is likely that it would require not only a quantitative performance/safety assessment, but also preparation of a "safety case" that is based upon multiple quantitative and qualitative arguments supporting the hypothesis that gas storage will be safe. Such an approach is also now widely adopted in radioactive waste disposal programmes throughout the world (Metcalfe, 2007 pers comm.).

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7 Methane storage in reservoir rocks - effects of (and on) microbial populations (Julie West, BGS)

As seen elsewhere in this report, methane storage underground in reservoir (porous) rocks and salt beds is a recognised technology. In the UK, porous reservoir rocks used or being considered for methane storage include Carboniferous sandstones, the Triassic Sherwood Sandstone, limestones and sandstones of the Middle and Upper Jurassic and sandstones of the early Cretaceous Purbeck Group. Methane is injected at depths between 450 m and 3 km, where temperatures will be above 35°C and the pressures greater than 70 bars. The composition of the methane will here be considered as consistent, being 'pure' and uncontaminated with other compounds.

This section is not a detailed literature review but briefly considers the effects of such injection on any deep subsurface ecosystem; biological influences on methane/rock interactions both in the reservoir itself and in cap rocks. Generally questions raised can be summarised:

1. Do microbes live in such deep reservoir rocks?
2. If so, what kinds of organism exist?
3. Can these organisms survive at such depths and could they survive the injection of methane?
4. If these microbes exist and can survive methane injection, what effects will they have on the methane?
5. Could these effects be detrimental to the containment or could other substances be produced as a result of microbial metabolism?
6. Can these effects be quantified?

7.1 THE MICROBIOLOGY OF THE DEEP SUBSURFACE

For any life to occur in any environment certain conditions for the synthesis of protoplasmic constituents and the liberation of energy necessary for life processes must exist. The synthesis of protoplasm requires water, a carbon source (organic or inorganic), nitrogen, phosphorus and sulphur, an energy source plus certain minerals (trace elements). The biochemical liberation of energy in the absence of light (as in a deep reservoir) requires:

- The presence of an electron donor such as oxidisable organic compounds or, in the case of chemolithotrophic organisms, oxidisable inorganic substances such as molecular hydrogen, ammonia, sulphide or ferrous ions
- The presence of an electron acceptor such as molecular oxygen, sulphate, nitrate, ferric compounds, carbon dioxide and simple organic compounds (McNabb & Dunlap, 1975)

Qualitatively, by this approach, it can be seen that most geological formations (including reservoirs) have the capacity to support at least a limited microbial population due to the presence of:

- Carbon sources - dissolved organic matter, carbonates, dissolved carbon dioxide
- Electron donors - dissolved H_2 and CH_4 and Fe^{2+}
- Electron acceptors - dissolved O_2, SO_4^{2-}, CO_2 and NO_3

However, the long-term stability of many carbon rich fossil fuels in the subsurface (including oil) prior to drilling does suggest that some biological factor is limiting (usually phosphorus) the growth of indigenous microbes on these resources whilst it remains unexploited. However, once the oil is tapped for commercial exploitation it then becomes available for microbial attack as

additional microbes, nutrients and energy supplies are introduced into the reservoir (Ehrlich, 1996). Thus it can be seen that the injection of methane into a reservoir should be viewed as yet another introduction of a potential carbon source and electron acceptor which can be used by those microbial groups whose biochemistry is capable of utilising the gas.

The deep subsurface is an extreme environment for life but it is not sterile. West & McKinley (2001) have shown that many different groups of microbe are found in a variety of geological environments, with total numbers approximately 10^5 to 10^6 organisms per ml groundwater. These include sulphate reducing bacteria, denitrifiers, iron bacteria and methanogens. Other work has indicated that complex ecosystems can live at depth in reservoirs (e.g. see references in Ehrlich, 1996). The deep subsurface can generate extreme conditions (pressure, heat) but Table 6 gives some examples of extreme conditions that individual microbial species can tolerate. Clearly, a reservoir environment of >35°C and 70 bars is not extreme. Indeed 35°C is an optimal growth temperature for many microbes.

7.2 THE CARBON CYCLE

The carbon atom, with its ability to be stable in a number of different oxidation states (-4 to +4) and its tendency to form stable covalent bonds, is very efficient at storing and releasing energy. The ability of carbon to absorb solar energy by forming reduced organic compounds and then release this chemical energy through oxidation reactions is the chemical basis of life on earth (Chapelle, 1993).

The pathways and mechanisms whereby oxidation and reduction reactions involving carbon occur are known as the carbon cycle. The central compound is carbon dioxide present either in the atmosphere as a gas, or in water as dissolved inorganic carbon species (CO_2, HCO_3^-, CO_3^{2-}). In terrestrial and near surface marine environments sunlight is available and carbon dioxide is reduced to carbohydrates via photosynthesis. The reduction of oxidised carbon in carbon dioxide to organic carbon releases free oxygen and results in aerobic conditions. Much of this organic carbon is aerobically oxidised via plant and animal respiration back to carbon dioxide.

A large amount of organic carbon produced by plant photosynthesis is cycled back to carbon dioxide by means of anaerobic oxidation. Anaerobic oxidation of carbon compounds occurs in many environments (such as soils, aquatic environments) and also in the deep subsurface (which would include potential reservoirs). In this overall process fermentative bacteria incompletely oxidise organic carbon producing organic acids, alcohols and molecular hydrogen. These simple reduced compounds are then completely oxidised by anaerobically respiring bacteria using mineral electron acceptors such as Fe(III) (by iron reducing bacteria), sulphate (by sulphate reducing bacteria) and carbon (by methanogens - refer Daniels et al., 1987). It should be noted that the interactions between sulphate reducing bacteria and methanogens are very complex and often methanogens are outcompeted by sulphate reducing bacteria because of the latters's high affinity for these simple compounds (Ehrlich, 1996). Nevertheless, the cycling of carbon under anaerobic conditions requires a cooperative food chain of a variety of microbial groups to achieve complete oxidation. The activity of these different organisms will give rise to by-products such as methane and hydrogen sulphide, which can cause souring of oil reservoirs. Methane produced by methanogens in the subsurface subsequently diffuses into aerobic environments where oxidation by methanotrophs takes place. Biological anaerobic oxidation of methane is also possible. The methanotrophs thus play a crucial role in the return of methane to CO_2 within the carbon cycle.

7.3 METHANOTROPHS

Methane can be used as a primary energy source by bacteria known as Methanotrophs. Some of these cannot use any other energy source ('obligate') whilst others are 'facultative' and can use other energy sources. Methane can also be oxidised by some yeasts and by some methanogenic

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archaea. With the exception of these methanogens, most methanotrophs are aerobic although many are microaerophilic preferring lower oxygen availability for development. Additionally, there is some evidence of the existence of anaerobic methanotrophs, which are not methanogens. For more details on the biochemistry see references in Ehrlich (1996).

Methanotrophs are generally found at aerobic/anaerobic interfaces in soils and aquatic environments that are crossed by methane and also in coal and petroleum deposits (Ehrlich, 1996). Given the generally small amounts of methane trapped in geological structures compared to the global carbon cycle it is clear that oxidation of methane is the common fate of biogenic methane gas.

7.4 THE INFLUENCE OF METHANE ON MICROBIAL LIFE IN A RESERVOIR ENVIRONMENT AND RESULTING CONSEQUENCES

As can be seen above, methane introduced into a reservoir can be regarded as a potential energy source for micro-organisms – particularly methanotrophs. The potential effects of enhanced microbial activity are:

1. Direct e.g. reduced volumes of methane, increased volumes of carbon dioxide
2. Indirect e.g. production of biomass with potential decrease in storage capacity; change in geochemical conditions

These effects could influence overall containment especially production of biomass with resulting production of biofilms. Such biofilms could, in the worst case, physically 'block' off areas of the reservoir thus altering permeability. If gas migration occurred into overlying geology and aquifers then the effects would be the same. However, the effects may have wider implications. For example, production of carbon dioxide could acidify groundwaters with resulting mobility of certain toxic species such as heavy metals.

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However, the consequences of methane injection on methanotroph activity will depend on the status of the reservoir itself – particularly whether aerobic/anaerobic interfaces are present. It is likely that methanotroph activity will be at very reduced levels in a completely anaerobic reservoir although the injection point should be regarded as potential interface. Thus effects may be quite localised. However, unless a pristine environment is selected where no drilling has taken place, the reservoir may have been subjected to previous geochemical and biochemical change and various organisms may have been introduced to the subsurface environment together with a variety of nutrients and energy sources from, for example, drilling fluids. Thus to evaluate the effects of the injection of methane it is important to first characterise the reservoir in terms of its basic geochemistry – particularly the existence of oxygen – and its existing capacity to support all microbial life. Once this baseline has been established then the subsequent changes to the ecosystem following methane injection can be evaluated.

In the first instance, such an assessment of the microbiology of the reservoir prior to injection can be achieved using a simplistic modelling approach (Baker et al., 1998). Nutrient and energy inventories of the solid (reservoir) and liquid (groundwaters) components in this environment (i.e. concentrations of species that can be used as nutrient and energy sources) would be used to calculate biomass. The approach assumes that all nutrients and energy are available for immediate use by organisms and thus it assumes a 'worst case' giving maximum biomass of the various groups of organism (including methanotrophs). It would also be possible to determine the useage of methane by methanotrophs with subsequent production of carbon dioxide. Limiting growth factors can also be established - it is possible that a nutrient and not an energy source may be controlling biomass. Following this basic evaluation it would then be possible to determine the maximum effects of methane injection on these populations. Following such basic calculations it would then be important to validate the results by performing basic microbiological analyses of the reservoir environment followed by laboratory experiments to

estimate the kinetics of nutrient/energy usage and by-product formation. Such experiments should be undertaken under realistic conditions using well-characterised materials.

7.5 CONCLUSIONS

- Microbes will exist in the deep subsurface reservoir. The environmental conditions produced at depth will not sterilise the rock. The ecosystem in the reservoir will depend on the geochemical conditions and the history of the environment. Indigenous microbial populations may have been joined by contaminant organisms and external nutrient and energy sources introduced during any drilling procedures. Thus injection of methane into the reservoir can be regarded as the introduction of yet another possible nutrient and energy source for microbial exploitation.
- In broad terms, if the storage reservoir is completely anaerobic then biological methane oxidation rates will be very low (although rates cannot be predicted). If oxygen is introduced into the system then oxidation rates will increase.
- The consequences of biologically catalysed methane oxidation on containment properties are complex and diverse. Simple modelling based on nutrient and energy inventories can give the maximum biomass and controlling factors on microbial growth in the environment. Estimates of maximum by-product generation can also be obtained by this approach. The results from these 'worst case' scenarios could then be constrained and validated by using experiments in realistic conditions.

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8 Subsidence, 'inflation' and microseismic activity associated with oil and gas production, gas injection and underground storage in depleting fields and salt caverns

This section outlines briefly the relevant considerations and potential problems associated with injection and storage of natural gas in depleted oil/gasfields (pore storage). The concepts regarding the effects of subsidence and 'inflation' (during gas injection) on caprocks, existing structures (e.g. faults in the caprock sequence) and associated subsidence, being based upon mining engineering experience, are also applicable to cavern storage, at least in the initial assessment stage. Problems of subsidence at saltfields are briefly reviewed in the final section (8.7).

It is a simple fact that all engineering activities performed underground in rock result in a finite effect at the ground surface (Cuss et al., 2003). For example, groundwater is a major source of drinking water in the UK and is abstracted from numerous boreholes located throughout the country. The pumping and abstraction of drinking water from porous geological formations (aquifers) for public water supply purposes can and does produce small surface ground movements in many areas of the country. But for the most part they are so small that they go completely unnoticed by the public and have no deleterious effects on property or infrastructure.

With subsidence it is really the gradient of the subsidence that is the problem (Cuss 2007, pers comm.). A metre or so of subsidence at the surface isn't necessarily a problem if that metre is spread over say one or two kilometres. Where it becomes a problem is when even a few millimetres occurs over a very short distance (like a fault). Of course, it also depends on where more general subsidence over a wide area occurs, and over what timeframe. If it is in coastal regions, then this might lead to encroachment by the sea in some areas (see below). However, even here it is not always straight forward, because the subsidence rate must also be balanced against the net sediment input to the region (from river systems into estuaries or sediment transport along the coast). This might keep pace with the subsidence and prevent encroachment by the sea.

Subsidence associated with oil and gas production is a well-known phenomenon and one that nowadays is predictable and can be modelled, rather like when considering mining problems. Fluid production and declining reservoir (pore) pressures may lead to a 'relaxation' of the reservoir. This movement may propagate to the surface, being typically manifested as a bowl-shaped subsidence (depression) at the surface, centred over the oilfield. The production of oil and gas from underground reservoirs gives rise to detectable effects at the surface, the magnitude or severity of which depends on a number of factors, including:

(a) Depth, lateral extent and vertical thickness of the reservoir
(b) Properties of the reservoir rock and of the adjoining rock formations
(c) Fluid pressure changes within the pores of the rock caused by oil or gas production and/or re-injection/withdrawal
(d) Major structural geological features such as faults
(e) Timescales of pressure variation and operation of the facility

Furthermore, during oil or gas production when 'relaxation' of the reservoir occurs or during the gas storage operations when the reservoir and caprock (or sequences overlying a salt cavern) are cyclically inflated and deflated, faults and fractures in the reservoir or cap rock may develop or be reactivated. Such faults and fractures can lead to increased or accelerated subsidence. They

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are also the cause of microseismicity described below and could act as conduits for gas migration.

Over the years, numerous small onshore oilfields have been successfully exploited for oil and natural gas in the UK. Whilst the general experience gained in the operation of small onshore oil and gas fields here in the UK is positive and very few problems have been encountered, subsidence associated with production has occurred offshore and around the world. Well-documented cases stemming from oil production operations in the North Sea, North America and elsewhere demonstrate that, in unfavourable circumstances, oil and gas production can cause damaging reservoir subsidence (e.g. Allen, 1968; Hermansen et al., 2000). It is, therefore, important to examine the potential for damaging surface ground movements resulting from cyclical changes in reservoir pressure in the UK, but this will very much be site-specific. The factors common to most reported problems are (Cuss et al., 2003):

- thick (i.e. vertically extensive) reservoirs
- the presence of weak and compressible porous rocks prone to irreversible (i.e. inelastic) pore collapse
- a substantial lowering of the reservoir pressure by oil and/or gas production with time

8.1 RESERVOIR SEISMICITY/MICROSEISMICITY, SUBSIDENCE ENGINEERING AND SURFACE GROUND MOVEMENTS ASSOCIATED WITH THE INJECTION OF FLUIDS AND/OR GAS

Underground withdrawal and injection of significant amounts of fluid or gas may modify (stress) the mechanical state of the porous (and eventually fractured?) strata involved (Fabriol, 1993). Materials, including rocks, when stressed (deformed) generate transient vibrations and emit acoustic signals (a phenomenon commonly termed microseismic activity or acoustic emission; AE) in the audible and sub-audible range. The study and analysis of such emissions can provide important information and data on the state of a gas storage reservoir during operation and degree of stability of the structure under study.

Generally, small-scale local modifications result, little altering the reservoir permeability and performance, and are not perceptible at the surface. Nevertheless, important effects have been noted in one or two specific cases and should be noted here. They are of two kinds:

- Surface effects – slow deformation related to reservoir compaction (withdrawal of e.g. fluids or gas) or inflation (re-injection of e.g. fluids or gas)
- Underground effects – reduction in permeability as a consequence of reservoir compaction, or induced seismicity due to sudden ruptures along pre-existing faults or weak joints caused by hydrocarbon production or the injection and withdrawal of gas

The possible damage and the seismic hazard related to induced seismicity resulting from the re-utilisation of old oil or gas reservoirs for fluid or gas storage must be taken into account and carefully assessed. This should be the case even if the abandoned reservoir has previously shown no anomalous behaviour (Fabriol, 1993).

The operation of a gas storage facility in a depleted oil/gasfield involves re-injecting gas into a depleted reservoir, which will increase the pore fluid pressure in the reservoir above the final operating pressures. The effect of re-injecting gas will be to decrease the effective stress acting on the reservoir rock and adjoining formations and this will actually decrease the possibility of future subsidence.

The operation of a salt cavern storage facility involves the creation of a large void in the salt body and the injection of gas. Should pressure in the void not be built up to compensate the overburden pressure, then creep of the salt is likely, as the overburden pressure effectively drives the salt to infill the lower pressure void by natural plastic deformation (creep – section 4.2). The process continues until the cavern and overburden pressures are equalized, or in the extreme

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case, the void closes up. The process would most likely be associated with subsidence to some degree. Injection of gas will 'jack-up' or keep the void open. However, if the pressure is built up too high, such that it becomes greater than the overburden pressure, then it could potentially cause some uplift of the overburden. It might also exceed the fracture limit of the overburden rock, leading to fracturing in the caprock.

Subsidence above producing oil and gas reservoirs is a direct consequence of the reduction in pore fluid pressures in the reservoir rock and in adjoining formations that have direct hydraulic connection with the reservoir. In simple terms, surface ground movement due to oil or gas production can be separated into two components (Cuss et al., 2003):

- reversible elastic component – when de-pressuring the reservoir by an amount $-\Delta P$ leads to a lowering of the ground surface and repressurising the reservoir by an amount $+\Delta P$ leads to an uplift of the surface which is of the same magnitude as the settlement.
- non-reversible inelastic component - associated with plastic deformation of the rocks and with phenomena such as fabric damage and pore-collapse that cannot be reversed by repressurising the reservoir.

The effect of re-injecting gas will be to decrease the time-averaged effective stress acting on the reservoir rock and adjoining formations. It is likely that this will actually decrease the possibility of future subsidence. A certain amount of uplift, the opposite of subsidence, will occur as the elastic component of stress is recovered during pressure cycling. The re-injection of fluids can prevent further ongoing ground movement associated with inelastic mechanisms and is widely used as a method of controlling oil field subsidence.

Surface ground movements associated with the reversible (elastic) component of rock deformation are rarely problematic. If the reservoir rocks and adjoining formations are moderately strong and, therefore, fairly incompressible, then the elastic strains and displacements associated with a reservoir pressure decline are usually quite small. The only exception is when the thickness (i.e. vertical extent) of the zone affected by the lowered fluid pressure is very large. In this situation, even though the elastic strains are quite small, the total displacement (i.e. the cumulative change in bed thickness over the affected zone) can be quite large.

Surface movements associated with the inelastic component of rock deformation can, under unfavourable circumstances, be much larger than those associated with the elastic component. Porous rocks subject to an increasing mean normal effective stress and declining pore fluid pressure may exhibit a "yield threshold". When the effective stress exceeds this threshold, the rock becomes progressively more compressible as brittle phenomena such as grain crushing and pore collapse become more important. These processes can (dramatically) alter the properties of a reservoir rock/interval.

In terms of strength, clay rich rocks have strengths generally described as weak to very weak. Limestone and sandstone units range from weak to strong rocks.

There are two types of deformation that can occur within a hydrocarbon reservoir that can lead to surface deformations and strains:

- Consolidation of the intact part of the rock - can result in a lowering of the ground surface (subsidence). The porous rock is 'work-hardened' during inelastic volumetric deformation and possible deformation mechanisms include shear-enhanced compaction, plastic flow, grain crushing and pore collapse.
- Movement along faults - fault mechanics either create new faults in the reservoir or environmental/rock parameters cause the existing fault network to move.

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8.2 DEFORMATION FROM PORE PRESSURE CYCLING

Geotechnical assessments of the reservoir and caprock successions are required to assess both natural (pre-existing) stresses within the succession and the effects of stresses resulting from the injection and withdrawal of gas (refer also section 3.4). The response of the rocks to these stresses requires careful determination, with measurements of their strength and an understanding of their deformation mechanisms.

8.2.1 Effective stress analysis using critical state concepts

In simple terms, if the mean effective stress during the gas storage cycle is less than the maximum value the rock has sustained over its entire geological history (i.e. the preconsolidation stress), then it is likely that the volumetric behaviour during pressure cycling will be largely elastic. If the mean effective stress during the storage cycle is greater than the preconsolidation stress, then the possibility that inelastic mechanisms might contribute to total deformation cannot be discounted.

Porous rocks that have undergone some form of diagenetic alteration leading to strengthening (e.g. cementation) usually exhibit a yield stress which is significantly larger than the value calculated from maximum burial depth (Cuss, 1999). The critical state approach can be used to determine what sort of deformation is expected within the stress conditions under consideration.

8.2.2 Transmission of pore pressure to the surrounding layers

Raising the pressure within the gas storage reservoir will result in the transmission of some pore fluid pressure to the beds immediately above and below the storage reservoir. Hydrocarbon reservoirs are normally associated with an overlying low permeability shale or clay caprock seal. This generally means that pore fluid pressure will not be modified significant distances from the gas reservoir. Because of low permeabilities in the sealing claystone caprock lithologies, pressure changes would be extremely slow in relation to the periodicity of the pressure variation due to storage.

8.2.3 Transmission of subsidence at depth to the surface

To estimate the amount of subsidence seen at depth transmitted to the ground surface, standard procedures adopted by the mining industry (Waltham, 1994) can be used (Cuss et al., 2003). This method calculates compression/extension, subsidence, ground strain and tilt. To calculate surface deformation, three parameters are required:

w – width of reservoir

ΔH – total change in reservoir thickness

z – depth of reservoir

8.3 FAULT REACTIVATION DUE TO SUBSIDENCE

It is a common observation that displacements associated with subsidence can become localized in faulted lithologies. Thus a fault may act as a boundary, which limits the lateral development of the subsidence trough. The displacements at such a boundary are focused on the fault plane. In effect, the movement on the fault is reactivated by the ground strains associated with subsidence.

If the fault cuts through all strata to the surface, its reactivation can cause a discontinuity in subsidence and strain profiles, which is sometimes apparent as a fault-scarp. This is a highly problematic and often damaging form of localised subsidence.

Oil and gas reservoirs are often present in tilted horst blocks bounded by faults with normal displacements. These faults may pass through the volume of rock affected by reservoir

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subsidence. Whether or not these faults could play a role determining surface ground movements depends on the magnitude of the strains and the detailed mechanisms of strain transmission. If the strains are small and largely elastic then the faults might play a minimal role. If the strains are larger and inelastic mechanisms such as pore collapse, fracturing and bed separation are implicated, then the faults are likely to play a more important role. To fully appraise the consequences of gas injection on faults at any particular site requires detailed site characterization that includes the collection of information on rock and fault properties.

8.4 TENSILE DEFORMATION

The maximum pore-pressure within the reservoir will dictate whether tensile deformation is induced in the reservoir rocks. Hydrofractures occur under conditions of stress when pore fluid pressure at the caprock-reservoir interface reduces the minimum effective horizontal stress below zero to the tensile strength of the rock. For hydrofractures to develop in preference to shear fractures the conditions:

$$P=\sigma_3+T \qquad \text{and} \quad \sigma_1-\sigma_3<4T$$

must be satisfied, where P is pore fluid pressure, σ_1 and σ_3 are maximum and minimum horizontal stresses respectively and T is the tensile strength of the cap-rock (Hubbert & Rubey, 1959; Sibson, 1995). Tensile strength is measured in units of force per unit area, which in the SI system is newtons per m^2 (N/m^2) or pascals (Pa), which in geological context will in all probability be in MPa. Pore fluid pressure can be estimated from the expected weight of the overburden, σ_3 from tectonic stresses and T from hydrofrac tests or laboratory experiments.

Natural gas reservoirs are generally found at discovery pressure gradients of between 5.4 and 11.8 kPa/m (0.78 to 1.6 psi/m). Katz & Coats (1968) found that no fracturing of the caprock occurred at or below gas pressures of 22.6 kPa/m (3.28 psi/m) of depth, suggesting that it could possibly happen at 33.9 kPa/m (4.92 psi/m) of depth, but that gas might open existing fractures at between 22.6 and 24.9 kPa/m (3.61 psi/m) of depth.

Therefore, to avoid leakage through the caprock, the applied overpressures must be below threshold displacement pressures and thus less than fracturing pressures. These values are higher than the maximum overpressures sustained during UGS. Thus, from a knowledge of the original reservoir pressures, displacement pressures (and thus fracturing pressures) and determination of rock properties, operating limits can be calculated for the facility, such that overpressures related to injected gas do not cause tensile failure of the reservoir or caprock.

Some American states (e.g. Indiana) stipulate a maximum wellhead injection pressure to ensure that the pressure during injection does not initiate new fractures or propagate existing fractures. The maximum wellhead pressure is calculated using the following formula:

$$P_{max} = (0.8\ psi/ft - (0.433\ psi/ft\ (Sg)))d$$

Where: Pmax = Maximum injection pressure (psia).

Sg = Specific gravity of the injected fluid.

d = Depth to the top of the injection zone in feet.

(refer http://www.in.gov/legislative/iac/T03120/A00160.PDF)

8.5 RESERVOIR SEISMICITY/MICROSEISMICITY ASSOCIATED WITH WITHDRAWAL OR INJECTION OF FLUIDS AND GAS

Examples of reservoir-induced seismicity (RIS) are frequent in the literature and cases of damaging earthquakes having been detected in and around oilfields that have produced for 10 years or more are known (Fabriol, 1993). RIS can occur either in cases of mass addition

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(injection) or withdrawal and is similar to that in mining situations involving mass removal of rock and involve the same rock mechanics theory.

RIS is extremely variable and manifested in many ways:

- Magnitude – micro scale to damaging earthquakes
- Time between injection and onset of (micro)seismicity – from a few days to several years
- Distance from point of injection – from the vicinity to tens of km

Complexities increase when extraction and re-injection are carried out in the same reservoir simultaneously or delayed in time, as for oilfields where water, gas or steam are injected for enhanced oil recovery (EOR) purposes. The most common scenario is injection leading to an increase in pore pressure, which decreases the effective stress on pre-existing faults that might be close to failure. This allows accumulated shear stresses to release, causing movement on the fault plane. The injection of fluid may also trigger damaging earthquakes along faults that are moved to a critical state by the principal regional stress loading, making it important that the present day tectonic context is fully understood (Fabriol, 1993).

RIS is slightly different to hydraulic fracturing, where the high pressured fluid or gas opens up pre-existing fractures or joints or creates new small scale fractures, which propagate into the rock mass. A number of cases are reviewed below (refer Fabriol, 1993).

8.5.1 Injection of waste fluid – the Denver earthquakes

Between 1962 and 1966, around 625,000 m3 of contaminated waste water was injected in a deep well drilled at the Rocky Mountain Arsenal (RMA), NE of Denver, Colorado USA (Hsieh & Bredehoeft, 1981). Injection was at a depth of 3650 m into a highly fractured Precambrian Gneiss. Between 1962 and 1967 over 1500 earthquakes were recorded, with three major ones of magnitude 5 or more in 1967 and which shook the Denver area causing minor structural damage. Previously, the last event felt in the area had been in 1882. By the mid 1980s, the earthquake activity had all but died away. The causes were attributed to movements along the fractures in the gneiss triggered by the increase in pore pressure due to injection.

8.5.2 Injection of fluid for EOR – the Cogdell oilfield, Texas, USA

RIS is fairly common in cases of high-pressure waterflooding in an oil reservoir for EOR (Davis & Pennington, 1989). At Cogdell, saltwater injection was initiated in 1956, seven years after the field was discovered. Seismic activity was detected in 1974 in the closest town, some 20 km to the south of the field. The earthquake activity was related to the field and hypocentres were close to the injection depths. From 1956 to 1983, 114 Mcm of salt water were injected through 119 injection wells located around the perimeter of the field.

8.5.3 Injection of fluid for EOR – the Rangely oilfield, Colorado, USA

Again, an EOR related case but where specific seismic monitoring was carried out at the same time as pressure tests that were performed to map the pressure distribution in the Permian reservoir (Raleigh et al., 1976). Injection was into the main reservoir at 1700-2100 m depth and only one fault oriented NE-SW was known on the anticlinal structure. The field was developed in 1945, with waterflooding having commenced in 1957-1958, prior to establishing the monitoring network in 1962. Earthquakes were, however, reported before 1962 with unconfirmed reports of felt earthquakes prior to the fluid injection. Consequently, it is not possible to establish any correlation between the initiation of waterflooding and the onset of seismic activity at Rangely (Fabriol, 1993). Waterflooding increased the fluid pressure in the reservoir above the original 190 bars. Studies in the 1970s suggested that the critical fluid pressure above which earthquakes could be triggered was 257 bars (3730 psi). Fluid pressures

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had reached 275 bars by the early 1970s, with more than 1500 minor seismic shocks recorded between 1963 and 1973 (Moran, 2007). Water pressures were then adjusted to maintain pressures below the critical pressure. Since 1963, 19 have had magnitudes between 2.5 and 4.7 on the Richter scale with the strongest, curiously, having been in 1995.

8.5.4 Exploitation of a geothermal field, The Geysers, California, USA

The geysers geothermal field is located 130 km N of San Francisco, with steam extracted straight from the reservoir (Oppenheimer, 1980). Steam is produced from over 200 wells penetrating the fractured reservoir at between 0.8 and 3 km depth across the field. Earthquakes have been known since 1969 and appear to be clustered in the production region, but occur randomly within the field, apparently not related to any through going fault system. It has been demonstrated that an increase in the number of earthquakes is related to an increase in geothermal production. Generally seismicity is very shallow, almost all is less than 5 km depth. There has been a volumetric contraction of the reservoir revealed by a subsidence rate of 3.4 cm/yr. The area of maximum subsidence coincides with the location of the maximum steam pressure decline in the reservoir. Two mechanisms remain plausible for inducing seismicity in the field:

- Volumetric contraction due to mass withdrawal may perturb the stress field, causing faulting in the reservoir rock
- Cementation of the fractures and fault surfaces leads to faulting rather than more ongoing aseismic slip in the rocks

8.5.5 Microseismicity induced within a gas storage reservoir, Germigny facility, Paris Basin, France

This facility located in the Paris Basin in northern France (Fig. 21) represents one of the few published examples of a microseismicity survey in a gas storage facility (Deflandre et al., 1993). The reservoir for the Germigny facility is a sandstone present in an anticlinal structure at around 750 m below sea level. Injection commenced in 1983, with the gas in storage between 1400 Mcm at the end of the winter period and 2100 Mcm following refilling at the end of the autumn (injection is from March to November). The microseismic survey was conducted with three permanent geophones in a single injection well, clamped to the casing wall at differing depths (783, 815 and 905 m). Between November 1991 and April 1992, 27 microseismic events were recorded, but posed no danger to the facility or its operation (Fabriol, 1993). Microseismic events were correlated with pressure changes in the vicinity of the observation well at the top and bottom of the reservoir interval, but the mechanism was not thought to be related to any faults (which had not been detected by drilling or seismic reflection data). Instead, the cause of the microseismicity was attributed to the reduction of effective stress along planes of different lithologies in an unfaulted sedimentary sequence (Fabriol, 1993).

8.5.6 Microseismic monitoring within gas storage reservoirs, Pennsylvania State University, USA

The Pennsylvania State University initiated a project on the optimisation of gas storage pressures in reservoirs in 1966 (Hardy et al., 1972a&b). Phase I of the project, which included analytical and model studies on cap and reservoir rocks, was directed towards the development of a criterion for establishment of optimum pressures in underground storage reservoirs and was completed in 1971. A PRCI monograph ("A Study to Evaluate the Stability of Underground Gas Storage Reservoirs") was published in 1972, with a conclusion that, from a rock mechanics point of view, optimum pressures in underground gas storage reservoirs where water containment is not a limiting factor could be of the order of those defined by the geostatic gradient (Hardy et al., 1972a).

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Phase II of the project ("Feasibility of Utilizing Microseismic Techniques for the Evaluation of Underground Gas Storage Reservoir Stability") commenced in 1971 (Hardy et al., 1972b), with the main objective being the investigation, under field conditions, of the feasibility of using microseismic techniques to monitor the stability of gas storage reservoirs. Field studies associated with Phase II were carried out firstly at the Wharton Field site (Pennsylvania), primarily developing the monitoring equipment and field techniques. These were then employed in a detailed study at the Lenox Field (Michigan). The studies concluded that optimum storage pressures in underground gas storage reservoirs could be, at least, of the order of those defined by the geostatic gradient, with no mechanical rock failure (plastic deformation or fracturing) of the reservoir or cap rock (Hardy et al., 1972a&b).

The results obtained during Phases I and II of Project PR 12-43, led to additional microseismic studies being undertaken at a third underground storage site using refined techniques and experimental facilities. Phase III of the study ("Microseismic Monitoring of Storage Reservoirs": Project PR 12-75), involved a detailed five-year investigation (between January 1st 1975 and December 31st 1980) of the microseismic activity associated with the injection and withdrawal cycle of the New Haven underground gas storage reservoir (Hardy et al., 1972b; Hardy et al., 1981; Hardy & Mowray, 1981). The study, which would provide a complete documentation of a reservoir pressurized above discovery pressure, investigated the stability of underground gas storage reservoirs. The main objective was to establish suitable criterion for optimum pressurization based on the principles of rock mechanics. One of the most significant results of the study was the fact that over the reservoir pressure range studied (approximately 220-623 psi), the microseismic event rate was found to decrease with increasing pressure. This indicates that the structural stability of the New Haven reservoir increased with storage pressure (Hardy et al., 1981).

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8.5.7 Reactivation or 'opening' of faults in the Salt Lake Oilfield, California

The Salt Lake Oilfield was largely abandoned but redeveloped by slant drilling during 1962, with the continuous production of oil, salt water and gas thereafter. Water has been re-injected into the field since 1980 and gas has been found to leak out of the oilfield and make its way to the surface (Appendix 5). It is believed that the 1985 and 1989 Fairfax gas leaks were the result of waste disposal or secondary recovery operations initiated by pressure injection of oilfield wastewater back into the fields. In addition to migration up old and poorly completed wells, increased pressures are thought also to periodically cause migration of gas along the Third Street Fault, allowing gas to escape to shallower levels and the surface (Hamilton & Meehan, 1992).

8.5.8 Discussion

It is worthy of note that the injection examples described above all concern water or fluid. This is fundamentally different to gas injection. Water is incompressible and therefore tends to hydraulically transfer pressure into the rock. Gases are compressible and transfer less pressure into the rock.

8.6 SUBSIDENCE ASSOCIATED WITH OIL AND GAS PRODUCTION AND GAS STORAGE FACILITIES AT DEPLETED OIL/GASFIELDS

Again, this is a major topic in its own right, with several cases of subsidence documented during exploitation of oil and gas fields in for example the North Sea (e.g. Holloway et al. 1996) and which cannot be adequately dealt with in this report. It is the aim of this section, therefore, to highlight one or two examples to illustrate the potential for and amount of subsidence associated with oil and gas production experienced in some areas.

8.6.1 Los Angeles Basin in general

Subsidence associated with oil and gas production has been described from the Los Angeles Basin, where the subsidence area maybe up to twice the size of the oilfield itself (Khilyuk et al., 2000; see Chilingar & Endres, 2004). The scale of the potential problem is illustrated in the case of the Wilmington Oilfield, where subsidence reached approximately 8.5 metres before corrective action was taken by implementing a major water injection program (Chilingar & Endres, 2004). Historical measurement data regarding subsidence in the Playa del Rey/Venice oilfield areas reveal almost 0.6 m of subsidence from the time that oil production began in the 1920s up to 1970 (Chilingar & Endres, 2004). Subsidence associated with the Torrance-Redondo Oilfield has also caused major damage when in January 1988, waves overtopped the breakwater protecting the Redondo Beach King Harbour Boat Marina and surrounding commercial properties (Chilingar & Endres, 2004). Investigations following the disaster revealed that nearly 0.6 m of subsidence had occurred under the breakwater as a result of oil production beginning in 1943. However, accelerated subsidence had occurred from 1956, following increased oil production.

8.6.1.1 Inglewood Oilfield subsidence

An incident at the Inglewood Oilfield reveals the potential problems and dangers that might be connected to oilfield subsidence if not monitored. The incident concerns the Baldwin Hills Dam in the south and west of the Inglewood Oilfield area of Los Angeles. In the late morning on December 14, 1963, the dam failed and the resultant flood of water caused massive damage to homes located below the dam and resulted in five deaths. The Inglewood Oilfield, discovered in September 1924, lies under the western half of the Baldwin Hills area. It covers about 4.9 km^2 and in 1963 had more than 600 producing wells, with at the time, the nearest reported production at the time of the reservoir failure being from three wells within 213 m of the south rim (Chilingar & Endres, 2004). Despite this, no monitoring of the oilfield for subsidence was undertaken.

Investigations into the failure revealed ground movement that correlated directly with production from the Inglewood Oilfield (Chilingar & Endres, 2004). The area of subsidence was elliptical in shape and centred over the oilfield, about 805 m west of the reservoir: subsidence at the reservoir site was about 0.9 m, compared to nearly 3.4 m at the subsidence bowl, contributing to differential settlement across the dam of approximately 0.15 m. Also revealed, was a large strike-slip fault system (the Inglewood-Newport Beach Fault Zone) that ran through the area, with numerous faults branching off the main fault. Drilling records indicated many of these faults had been intersected in wells drilled across the area. The post-accident investigation suggested that some of these faults had been re-activated and caused rupturing of the asphaltic membrane used as a water seal over the floor of the dam.

8.6.2 Ekofisk Oilfield, North Sea

Subsidence is an ongoing phenomenon in oilfields of the North Sea, with the Ekofisk Oilfield in the Norwegian sector of the North Sea being a high profile example. In the mid-1980s it was discovered that the oilfield was suffering from an unexpected degree of subsidence that caused problems with the interconnected series of platforms. Detailed geological investigation revealed the problem was related to delayed compactional diagenesis of the Chalk Formation from which the oil is produced. Production of hydrocarbons meant that water replaced the oil and began to dissolve the Chalk, which was redeposited in a more compact, lower porosity configuration. Total subsidence was almost 6 metres and required that the platform legs were cut and all the interconnected platforms were jacked-up by this amount and new leg sections inserted.

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8.7 SUBSIDENCE AND DAMAGE OCCURRING AT SALTFIELDS DURING SALT EXTRACTION AND GAS STORAGE OPERATIONS

This section briefly outlines some of the problems encountered at operating saltfields (both dry mines and brine extraction) and during salt cavern gas storage operations. Examples of subsidence and damage resulting from poor operational procedures and observed subsidence rates are described, with further detail available in Appendix 2.

The impacts of mining and solution mining operations to man-made surface structures and other features are relatively well known and studied. The effects range from mild subsidence across wide areas to catastrophic failure and collapse of the overburden, resulting in the formation of a (often deep) crater at surface, as has occurred in salt workings in Europe and in the UK at the Preesall brinefield (Lancashire – refer Wilson & Evans, 1990; Jackson, 2005 – section 8.7.2.1.1 and Fig. 5b).

8.7.1 Subsidence occurring with salt cavern formation and overburden/caprock stability

As alluded to in section 2.2.7.3.3, all solution-mined caverns, be they brine extraction or gas storage caverns, converge as they very gradually shrink due to salt creep (Bérest & Brouard, 2003). This occurs until either the salt fills the void or confining pressures and cavern pressures are equalised, and is associated with varying degrees of subsidence as the salt moves into the void.

Elsewhere in the report (section 4.2), the ability of salt to deform either in a ductile (plastic) or brittle manner, depending on the temperature, stress state and strain rate is outlined. At temperatures expected for the salt-dissolution subsidence process, the primary creep (or ductile-deformation) mechanisms for rock salt are glide and solution precipitation (Urai et al., 1986b). If groundwater penetrates the subsiding salt mass, deformation by solution-precipitation creep is capable of producing strain rates that are orders of magnitude higher than are possible in relatively dry salt at the same stress states (Davies, 1989). Two basic types of subsidence exist (Anderson & Browns, 1992):

- very slow subsidence characterised by predominantly ductile deformation – salt creep
- relatively rapid subsidence characterised by predominantly brittle deformation (Ege, 1979; Davies, 1989).

These two types of subsidence represent the end members of a continuous range of subsidence processes. The process of salt creep at depth into the cavern area can lead to closure of caverns that are not constructed or operated correctly (see Appendix 5). This process typically generates an upward-expanding zone of subsidence that is transferred to the surface with decreasing amplitude over a wide cone of influence. With time, the ground surface over an intact cavern will deform into a broad shallow depression (Warren, 2006), referred to as 'bowl subsidence' or 'zone of draw', a term originally used in coal mining to describe the distance on the surface to which the subsidence or creep extends beyond the underground workings (e.g. Thrush, 1968). It is, therefore, similar to 'trough subsidence' at the surface above 'long wall' or 'room and pillar' mining operations. This phenomenon is normal and predictable using fairly standard mining calculations and is more obvious above shallower storage caverns. It will occur over the entire footprint of an individual cavern projected vertically upwards to the ground surface and beyond into an area determined by what is termed the 'angle of draw' (e.g. Jeremic, 1985). For relatively flat-lying strata, this is commonly held to be c. 35° to the vertical. The greater the cavern depth, then the greater is the extent of the zone of subsidence beyond the limits of the undergound void. To illustrate, for a cavern developed at depths of 300 m to 600 m, the area within which subsidence could occur would extend between about 210 m and 420 m in all directions beyond the limit of the cavern projected vertically to the ground surface. However, it should be noted that the amount of subsidence that occurs is inversely related to depth, i.e. there is a depth below

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which closure of an opening of a particular size or shape does not give rise to subsidence at surface.

Bowl subsidence does not, however, generally become a problem unless the roofspan is breached and the rate of subsidence increases (Warren, 2006). This can lead to brittle deformation and collapse of the overburden followed by ingress of water, perhaps further escalating the subsidence problems due to dissolution of the salt. Brittle deformation is characterized by an inverted-cone-shaped vertically migrating collapse cavity or chimney (refer Warren, 2006).

It has been suggested that in a brittle collapse zone, water ingress could lead to ongoing dissolution but facilitate relatively rapid creep of adjacent salts (as a result of the presence of water), back into the dissolution cavity. This could conceivably help to prevent the formation of large cavities and subsequent catastrophic collapse. A consequence would be more gradual subsidence, the horizontal extent of which would increase upwards as dissolution proceeded through time (Anderson & Browns, 1999).

For the case of developing a large cavern field the closure mechanics become more uniform. Once the width (of the field) becomes larger than the overburden thickness, large-scale stress arching effects in the overburden become less important All creep strains in the salt horizon are accommodated by direct downward movement of the overburden, with all 'pillars' (undissolved salt between caverns) carrying the full weight of the overburden (Mraz et al., 1991; Dusseault et al., 2001). This process will accelerate closure when compared to an isolated cavern, where some of the stress concentration (i.e. shear stress) is transferred farther from the cavern through the rigidity of the non-salt roof rocks above the cavern. If all other factors are equal, then an isolated cavern will close more slowly that a cavern group (Dusseault et al., 2001).

Measured land subsidence rates vary above salt caverns, due partly to the differing depths and operational procedures at any particular cavern. In the 1980s, measured subsidence rates over shallow caverns in the US SPR ranged up to 40-50 mm/yr at facilities in Texas and Louisianna (Warren, 2006). Deeper caverns, such as that at Tersanne in France (c. 1450 m below ground level), are associated with much lower rates of around 6-8 mm/yr. Since the late 1980s, most purpose built storage caverns have been filled and maintained at higher pressures than was the case in the 1970s-1980s. The result is that salt creep and resultant subsidence has been reduced (Thoms, 2000; Warren, 2006).

Ongoing and continuous monitoring/surveillance and reappraisal is required at most storage sites. However, understanding of the causes, rates and magnitudes of the subsidence permits site operations to continue in most cases.

8.7.1.1 Observed and calculated rates of subsidence associated with gas storage and brine caverns

This section briefly details some observed and calculated rates of subsidence associated with gas storage and brine caverns.

8.7.1.1.1 Bryan Mound, Big Hill and West Hackberry SPR salt cavern storage facilities, USA

A series of cavern storage facilities have been constructed in salt domes of the Gulf Coast, USA including Bryan Mound, Big Hill and West Hackberry. All have been monitored for the effects of subsidence (Warren, 2006). Between 1982 and 1988, the subsidence rate at Bryan Mound was 24.4-36.6 mm/yr. This fell to between 6.1 and 24.4 mm/yr in the period 1988-1994 and 3.1-15.2 mm/yr from 1994-1999. The reduction in the subsidence rate by around 70% was related to increasing cavern pressures (Warren, 2006). At Big Hill, subsidence rates ranged from 6.1-15.2 mm/yr between 1989 and 1994, but reduced to 6.1-9.1 mm/yr between 1994 and 1999. The lower rates overall at Big Hill may, to some extent, be related to a thick (300 m+) brittle caprock overlying the salt dome (Linn & Culbert, 1999; Bauer, 1999; Warren, 2006).

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In contrast, however, the West Hackberry storage facility is an example of extensive, major subsidence resulting from mainly salt creep closure of the SPR storage caverns below (Magorian et al., 1993; Neal & Magorian, 1997). Even following pressurisation, the subsidence rate remained high at 76.2 mm/yr (Warren, 2006), which although other causes of subsidence have been found to contribute, is mainly attributed to salt creep.

8.7.1.1.2 Example of predicted subsidence associated with proposed gas storage salt caverns in the Preesall Saltfield, NW England

During the Canatxx application to develop salt caverns for gas storage, studies of the likely subsidence associated with cavern development and operation were undertaken by two cavern design experts (Dr J Ratigan & Prof K Fuenkajorn). In the design of a gas storage cavern, a pressure range is defined within which the caverns should operate at given depths and geostatic pressures. The upper (higher) pressure limit is designed to prevent overpressurization that could cause fracturing of the rocks. The lower operating pressure is designed to stop the inward movement of the cavern walls due to salt creep. Pressures for the operating caverns were anticipated to be in the range 25-75 bar (368-1103 psi), for 100 m diameter caverns, the tops of which are between 220-425 m below ground level (refer Table 1 in Heitmann, 2005). The subsidence estimates for these conditions were calculated using industry recognised modelling methods and covered a range of possible cavern sizes and designs. The subsidence rates derived were:

- An average rate of 0.2-0.3 mm per year, maximum being 0.5 mm (Dr J Ratigan)
- An average rate of 0.4-0.8 mm per year, maximum being 1.4 mm (Prof Fuenkajorn)

For reasons not entirely clear, it was noted in the report by Hyder Consulting (2005) that Dr Ratigan considered cavern sizes that were generally smaller in size than those reviewed and modelled by Professor Fuenkajorn.

8.7.2 Problems of subsidence in saltfields not related to wet rockhead or linked to gas storage

Problems of stability and subsidence have arisen when parts of the salt mass are extracted in a poorly managed way, or salt bodies with previous or ongoing drilling activities. This has led to disturbance and collapse of the caprock sequence(s), with cases of ingress of water that have led to enhanced salt dissolution and subsidence. The following far from exhaustive review summarises the problems that have been encountered in saltmine or brine field areas. It is emphasised that they are *not* as a result of operations associated with gas storage, but are merely presented to illustrate the problems that have been encountered by poor mining or operational practice or site characterisation, either when extracting salt or drilling in areas of previous salt extraction. A comprehensive review of the various failure mechanisms of the caprock sequence above saltmines or caverns experiencing problems and that lead to the development of 'collapse chimney's' or pipes is provided by Warren (2006).

The surface effects of the events described here and in Appendix 2 (see Fig. 5b-d) are of particular interest when assessing the risks posed to existing or future infrastructure (gas pipelines, compressor stations etc.) in areas under consideration for gas storage in salt caverns.

8.7.2.1 PROBLEMS AT SALTMINES AND BRINE FIELDS

Appendix 2 details briefly the nature of problems encountered at saltmines and brinefields where catastrophic ground failure arose through poor mining and working practices. Examples found in Romania, Italy, Poland, France and the USA illustrate how poor mining and cavern development can lead to significant areas being affected by subsidence and collapse. They represent potential problems that could arise from inadequate site characterization and poorly managed solution

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mining of a cavern or cavern field without due regard to, or control over, the shape, dimension or long-term geological stability of the resulting cavity/cavities.

In some countries large areas are now unstable and unusable, whilst in Kansas (USA), the collapse of brine caverns and formation of significant surface collapse hollows and craters has led to problems with and damage to surface infrastructure (Fig. 5c&d). The development of such features is of potential importance to sites being considered for gas storage where above ground gas pipelines would be present onsite. The extraction of brine from the eastern areas of the Preesall Saltfield in NW England reveals similar problems of surface subsidence and collapse structures and is outlined in the following section.

8.7.2.1.1 Subsidence associated with salt caverns related to former brining operations in the Preesall Saltfield, NW England

ICI have for many decades extracted salt and brine from the Preesall Saltfield near Fleetwood, Lancashire. Many caverns were developed and the earlier examples are often associated with subsidence problems due to uncontrolled brining. In general, these collapse craters and subsidence features are located in the older (eastern) areas of the worked brinefield, where the brining operations were aimed at removing as much salt as possible. Often this removed the supporting and protective roof salt, causing damage to the overlying mudstones and leading to their collapse into the cavern with time. As a consequence, large subsidence hollows and collapse structures of varying size have developed, some of which are now the sites of deep craters and lakes (Fig. 5b and Wilson & Evans, 1990).

The later brine caverns were located further west along the western limit of the worked saltfield and appear more stable. A subsidence monitoring system was established by ICI, although it appears not to have been kept up to date. On abandonment, the cavities were filled with brine and wellheads were sealed, with the natural creep of the salt (and thus tendency for cavern walls to move in and close the cavern) left to equilibrate with the pressure of the brine in the caverns. This build-up in pressure due to salt creep is clearly illustrated by the brine geyser described in section 2.2.7.6.1.

The collapse chimney's of course may provide pathways for the downward movement of water potentially adding to the dissolution of salt at depth. However, it is likely that below a certain depth, there is no groundwater circulation. Any waters that penetrate down below this depth will become saturated and may effectively protect the salt from further dissolution. The presence of such structures and the brine saturation levels would require careful study and monitoring to ensure activities elsewhere in the brindefield did not affect ground conditions, permitting movement of fresher waters and possible renewed salt dissolution for example.

8.7.2.2 PROBLEMS ASSOCIATED WITH OLD WELLS IN SALT BEARING SUCCESSIONS

Certain events in the USA and Algeria, whilst closely related to the previous section, are worthy of mention in their own right and highlight the problems of old oil and brine wells in areas of halite and old mine workings (Warren, 2006). An example of a mine intersecting an old well at the Winsford Mine in the Cheshire basin is also reported and all incidents (described in more detail in Appendix 2) are relevant to UK proposals. Again, the list of such examples in Appendix 2 is not exhaustive, merely illustrative. However, in all examples, old wells led to problems of water ingress and instability of a mine or areas of a brinefield. They illustrate the problems and dangers that can occur in areas as a result of inadequate site characterization and liaison with relevant authorities, in the process of defining positions of old abandoned oil or brine wells etc. Without rigorous/diligent site characterisation, they could present similar problems at UK UGS sites. The scenarios this might cover in the UK context could include:

- Old wells (including non brinewells) not properly capped and abandoned might provide pathways to depth for fresh or undersaturated water that has the potential to cause

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unknown solution and thus cavity formation in the salt formation at around the level of proposed caverns

- A brine cavern being constructed and intersecting a previously unknown (and which might remain unknown until cavern pressure tests are conducted) well, leading to possible risk of communication or failure of the pressure test
- Previously unknown wells into the salt storage formation not intersecting the cavern, but that might, if the cavern is operated in brine compensated mode, ultimately be encountered or intersected as a result of unmonitored cavern enlargement during storage operations

The scenarios and examples described in Appendix 2 demonstrate the requirement for careful preparatory work that includes both checking of borehole siting records and detailed ground investigations.

8.7.2.3 Problems associated with new oil exploration wells in salt bearing successions and former mined areas

An incident in America, involving the drilling of an oil exploration well in 1980 (described in more detail in Appendix 2), is of likely relevance to some UK proposals where salt beds occur within areas having hydrocarbon potential and in which exploration is possible in the future (e.g. the Cheshire Basin, NE England, Dorset). During the drilling of the well from a pontoon in a lake, an unused section of a salt mine was intersected around 350 m below lake level. This resulted in rapid flooding of the mine workings and emptying of the lake. It again illustrates the problems and dangers that can occur in areas as a result of inadequate site characterization and liaison with relevant authorities, in the process of defining positions of previous and abandoned mine workings. The scenarios this might cover in the UK context would include:

- the drilling of an exploration well in an area of gas storage caverns, especially if the well were to be deviated from the surface position some distance to the final depth location
- drilling a well in an area that might intersect old mine or brine cavern workings and with gas storage caverns close by. This could cause water ingress and a sudden collapse that might lead either to a chain reaction and rapid expansion of the affected area, or slower dissolution and cavity formation that then impacts upon the area of the storage caverns and ultimately their integrity and safety

Again, the examples demonstrate potential scenarios that illustrate the requirement for careful preparatory work that includes both checking of records and detailed ground investigations.

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9 Incidents and casualties at underground hydrocarbon storage facilities

This section outlines documented problems encountered at UFS facilities and incidents of leakage of varying degrees of severity (Tables 7 – 11; see also Evans, in press). Appendix 5 provides more detailed descriptions of the cause and where possible, the resolution, of each event. In the main, reports of problems are from American and European sites. At this stage of the survey, no incidents have been found reported from Eastern Europe or Russia, although we expect them to have occurred.

The problems and incidents are dealt with by storage type (depleted reservoir, aquifer, salt cavern and abandoned mine) and country. Overall, 65 reports of instances of problems encountered at UFS facilities have been found. Of these, 27 have been at salt cavern facilities, 17 at aquifer and 16 at depleted oil/gasfields (Table 7). Escape or leakage of stored product appears most prevalent at salt cavern storage facilities, which are generally shallower than those in oil or gas reservoirs and as described in Chapter 2, differ considerably from facilities constructed at depleting/depleted oil and gasfield sites. Only 9 deaths related to UFS have been found reported in the literature, with around 62 injured and circa 6700 evacuated. However, the latter figure does not include figures from the village of Knoblauch, near Ketzin (west of Berlin) that was apparently permanently evacuated following one gas leak (see section 9.2 and Appendix 5). Of the reported deaths, 8 have occurred at salt cavern facilities and all of these have been in America (West Hackberry, Mont Belvieu, Brenham and Hutchinson). A ninth death was reported at the Ketzin gas storage facility during the 1960s (NJ Riley, pers comm., 2007). Indeed, 53 of the reported incidents have occurred in America, with California (12) and Illinois and Texas (10 each) having the highest number of incidents found. The 65 incidents have, however, been of varying cause, severity and nature, with some involving only minor problems that were quickly rectified and at no stage threatened failure of the facility or release of product.

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9.1 DOCUMENTED INCIDENTS AT DEPLETED OIL AND GAS FIELD FACILITIES

As described in Chaper 2, underground gas storage operations were first undertaken at an operating gasfield in Welland County, Ontario (Canada) in 1915. The first gas storage facility in a depleted reservoir was built in 1916, using a gasfield in Zoar near Buffalo, New York (USA), and remains the oldest operational facility (WGC, 2006). Gas storage in depleted oil/gasfields now represents around 76% of the total number of UGS facilities (Plaat, 2004 & this volume; EIA, 2006).

This study has identified 16 documented problems and incidents at depleted oil and gas field facilities (Tables 7&8), with 3 of these cases (19%) having involved casualties or evacuees. No fatalities have been reported. Relative to today's number of operational facilities (478), which are fewer in number than in recent history, this represents an incident rate of 3%, with 0.63% involving fatalities/casualties/evacuees (Tables 2,7&8). Fourteen (c. 88%) of the cases (Table 8) have occurred in America, of which, 11 (c. 69%) have been in California. In all, 5 people have been injured and around 83 people evacuated during reported incidents. All cases involve injection and storage of natural gas.

In terms of the main failure mechanisms or difficulties encountered at depleted oil/gasfield facilities, 2 scenarios with 5 incidents (c. 31%) apiece were associated with:

- failure of the well or casing (due to cracks, damage, corrosion or during repair/maintenance) at Fort Morgan, Colorado (State of Colorado, 2006) and 3 in California. In the latter, 2 were related to repairs of wells and 1 was due to damage

during an earthquake (Vector Magnetics, 2007). All 3 Californian well incidents were rectified by directional drilling of sidetracked wells, isolating and plugging the damaged sections (Appendix 5). The fifth case of problems with a well was an anomalous pressure rise in the annulus of a gas storage well at the Breitbrunn/Eggstatt Gasfield (Bavaria, Germany) in 2003 (Bary et al., 2002; Überer et al., 2004). The incident is not reported as having led to serious problems, with repairs to the well casing quickly and successfully undertaken (Überer et al., 2004).

- migration from the injection footprint, due effectively to overfilling at: (East) Whittier (Benson & Hepple, 2005), Epps (Coleman, 1992), Playa del Rey (Reigle, 1953; Chillingar & Endres, 2005) and Castaic and Honor Rancho (Khilyuk et al., 2000; Davis & Namson, 2004). At Playa del Rey, gas leaking from the reservoir into the adjoining Venice Beach accumulation was known since the earliest days of operation (Reigle, 1953; Chillingar & Endres, 2005). Gas migration to shallower levels was believed to be related, in part, to faulting of the caprock in the Castaic Hills & Honor Rancho, Playa del Rey cases and the El Segundo facility (Reigle, 1953; Khilyuk et al., 2000; Exploration Technologies Inc., 2000; SoCal, 2004; Chillingar & Endres, 2005).

Three incidents (18% of cases) were related to problems with above ground infrastructure at: McDonald Island, California (Delta Protection Commission, 1997), Playa del Rey (SoCal, 2004) and the Rough Storage facility, Southern North Sea (HSE, 2006; Centrica, 2006). The offshore Rough Gas Storage Field, about 31 km (20 miles) off Withernsea on the East Yorkshire coast, represents the one recorded incident in a depleting gasfield in the UK, on the 16th February 2006. An explosion and fire occurred on the Bravo 3B platform, which led to the evacuation of 31 workers, whilst 25 essential staff remained on the platform. Two workers suffered from burns and the effects of smoke inhalation and were treated in hospital. The cause of the accident appears to have been the catastrophic failure of a cooler unit and an explosion in that vicinity (HSE, 2006; Centrica, 2006 – Appendix 5).

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9.1.1 California and the case of numerous old oilfields with migrating gas in an urban environment and the impact on the perception of gas storage safety issues.

California provides 11 (c. 69%) of the UFS incidents at depleted oil/gasfield sites and c. 18.5% (12) of all (65) UFS incidents, somewhat distorting the statistics and is worthy of further appraisal. The region has been an area of intense hydrocarbon exploration and production since the latter part of the 19th and early part of the 20th centuries (Chilingar & Endres, 2005). Over 70 oilfields have been discovered in the Los Angeles Basin alone (Appendix 5) and many oil wells were drilled on these fields in very close proximity to one another (refer figs 22&23 and http://www.consrv.ca.gov/DOG/photo_gallery/historic_Mom/photo_01.htm). In the UK, there has been no drilling on the intensity seen in American urban environments at the turn of the 20th Century, sites of which became heavily populated.

The depleted Playa del Rey (PDR) oilfield is one of 5 gas storage facilities that operated within a 64 km (40 mile) radius of the Los Angeles region until the late 1990s (Chilingar & Endres, 2005). Hundreds of oil wells were drilled from derricks that once blanketed the landscape (Fig. 22b). The majority of these oilfields are now abandoned, but the area has been left with a legacy of old, disused wells, the locations of which are often poorly known, but that now lie beneath densely populated urban areas.

The oilfields in the Los Angeles area provide numerous instances of potentially explosive methane gas seeping to the surface in heavily built-up areas, raising the possibility of a major incident (Hamilton & Meeham, 1992; Renwick & Sandidge, 2000; Gamache & Frost, 2003; Chilingar & Endres, 2005). The Fairfax and Belmont oilfield gas leaks are of particular interest when incidents at the gas storage facilities developed at the Montebello and PDR oilfields are considered. The problems associated with, and the failure to completely retain injected gas in the 5 storage facilities developed in depleted LA fields, could be explained by and be related to, the

rather unique geological environment represented by the Los Angeles area. The LA incidents may, therefore, not be typical of the likely problems encountered in depleting oil/gasfield storage elsewhere and may distort the gas storage safety figures.

Leakage problems in existing fields have been most vividly illustrated in incidents at, for example (Figs 22a,c&f & 23), Fairfax (1985, 1989, 1999 and again in 2003; Gamache & Frost, 2003; Chilingar & Endres, 2005), La Brea Tar Pits (associated with the Old Salt Lake and South Salt Lake oilfields respectively) and at a school site in Belmont (the Los Angeles City Oilfield). In March 1985, methane that had accumulated in the basement of the Ross Department Store ignited and caused an explosion that injured 23 people. Fires also broke out along surface cracks and fissures that developed nearby and burnt for days after the explosion (see Gamache & Frost, 2003). The escaping gas originated from the Old Salt Lake Oilfield lying immediately beneath the area and had migrated up along at least 2 wells and the Third Street Fault that reached surface beneath the department store. One of the wells was an old abandoned vertical well, but the second was a relatively modern inclined well that was found to have suffered corrosion below 366 m depth (Chilingar & Endres, 2005). A very similar gas leak incident occurred on February 7th 1989 across the street from the 1985 explosion (Chilingar & Endres, 2005). In January 2003, serious gas leakage problems were discovered in the vicinity of Allendale and Olympic Boulevard, in the Fairfax area. The gas had been leaking to the surface along abandoned and poorly completed wells (Chilingar & Endres, 2005). A leak was detected and a potentially major hazard averted in 1999 at the intersection of Wilshire and Curson streets just south of the La Brea Tar Pits above the South Salt Lake oilfield, (approximately 1.6 km from the Fairfax incidents).

Gas migration problems were also identified during the $200-million Belmont High School development, in Northwest downtown Los Angeles (Fig. 23b). Construction was halted by the discovery of high levels of methane in the soil across the site. Geological investigations revealed the gas originated from the underlying Los Angeles Oilfield, with a fault below the school site thought likely to have provided a pathway to the surface. Archival photos of the area circa 1890 also show hills blanketed by oil derricks, the majority of sites of which are not documented and are now covered by homes, business premises and the site of the school (Fig. 23c&d). A decision to abandon work on the school was taken in January 2000, although pressure to recommence work remains.

These incidents were all related to the presence of old corroded wells, many of which were drilled before official records were kept and over which high density housing (largely apartment buildings) had been developed (Chilingar & Endres, 2005). Other contributory factors included blocked ventilation wells and ongoing oil and gas production involving waste disposal or secondary recovery operations increasing reservoir pressures (Hamilton & Meehan, 1992; Chilingar & Endres, 2005). Increased pressures had driven the gas out of the storage reservoir and up old wells with poorly completed or corroding and deteriorating steel casings and cements. The overpressuring also caused the periodic 'opening' of the Third Street Fault, further exacerbating the situation (Hamilton & Meehan, 1992).

9.1.2 Gas leaks at the Montebello and Playa del Rey converted oilfield gas storage facilities

The Montebello and PDR oilfields in the Los Angeles area were discovered many decades ago and during production, hundreds of unregulated (or unmonitored) oil/gas wells were drilled, the majority of which are now abandoned (Fig. 22b&e). Many of these wells were drilled before today's rigorous drilling and completion standards were implemented or applied (Chilingar & Endres, 2005). Following production, the oilfields were converted to gas storage facilities.

In the case of Montebello, gas had been injected at a depth of around 2286 m and was subsequently found to be leaking to the surface along old wells, again, many of which were drilled in the 1930s (Chilingar & Endres, 2005). Investigations have revealed that the old well

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casings and cements are unable to cope with the increased pressures, allowing high-pressure gas to enter the old wells and migrate to shallower depths but not to the surface (Benson & Hepple, 2005). The problems encountered led to the facility being closed in 2003 (Chilingar & Endres, 2005; EIA, 2006).

The PDR Oilfield was discovered in 1929 and is developed in the western Los Angeles Basin, about 17.5 km WSW of downtown Los Angeles. Between 200 and 300 operational or abandoned oil/gas wells have been drilled across the field, although the precise total is unknown, with areas once densely covered by oil derricks (Fig. 22b). The field comprises two accumulations separated by a NW-SE trending ridge of basement (Mesozoic) rocks referred to as the Santa Monica or Catalina Schist (Fig. 24): a northwestern 'Ocean Front' or 'Venice Beach' accumulation and a southeastern accumulation, known as PDR that extends north of the Ballona Creek (Eggleston, 1948; Landes et al., 1960; Barnds, 1968). The field quickly depleted and in 1942, as part of the wartime effort, it was converted for use as a gas storage facility, full-scale operations commencing in June 1943 (Barnds, 1968). PDR has continued to be used as a storage facility and since 1945 has been operated by Southern California Gas (SoCal). Investigations have revealed that gas has, since the earliest days of operation, leaked from the reservoir both into the adjoining Venice Beach accumulation and also upwards to surface via faults, old wells and intermediate 'collection zones' (Reigle, 1953; Chillingar & Endres, 2005).

The PDR area has been the focus of attention since the 1990s as land in the Venice, Ballona Creek and PDR region, immediately overlying the PDR oilfield is being considered for major urban development (e.g. Davis & Namson, 2000; Chilingar & Endres, 2005). However, there are numerous documented instances of gas leaking to the surface at PDR, with gas seen bubbling up in waters of the Marina and Ballona Creek/Channel, in shallow lakes alongside old well casings (Fig. 22d), and in standing water following heavy rains (Chilingar & Endres, 2005). Analyses of the gases from the Ballona Creek and other leaks indicate that it is seeping up from deep underground with estimates for the rate of gas loss due to uncontrolled migration and/or seepage into the atmosphere put at around 2.8 Mcm per year (Tek, 2001; http://www.saveballona.org/expert.html).

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The change of land use has led to problems, with the PDR area the centre of a major ongoing battle to prevent the development of a large housing project over the oilfield. When excavations began for the actual construction of the housing development, it was discovered that wells, abandoned as recently as 1993 to make way for the housing development, were found to be leaking (Chilingar & Endres, 2005). In each case, homes were constructed over the old wells after minimal efforts were taken in an attempt to reseal the wells. There have also been attempts to install a membrane to try and stop the migration of gas into buildings. Further problems are posed by some of the larger buildings. These require the driving of piles up to 15 m down through the poorly consolidated river terrace and wetland marsh sediments into solid rock and that provide further potential gas migration pathways.

Opposition groups to the Playa Vista development have alluded to the Fairfax and Belmont gas seepage incidents, highlighting the problems of old wells and possible unmapped faults in the area, as valid reasons for the abandonment of the project. The Playa Vista development and associated problems clearly highlight the difficulties encountered with urban encroachment into oil and gas fields, not just within the Los Angeles Basin, but anywhere with historical oil production (Chilingar & Endres, 2005).

9.1.3 Hydrocarbon exploration well, Hatfield Moors, England

Although not a gas storage incident, the Hatfield Moors gas well explosion and fire has some relevance, as the depleted gasfield has, since 2000, become one of the UK's few operational gas storage fields (Ward et al., 2003). The Hatfield Moors Gasfield was discovered by accident in December 1981, when the Hatfield Moors No.1 exploration well unexpectedly encountered gas in a Westphalian sandstone reservoir at around 425 m below ordnance datum (OD). This led to a

major gas escape that ignited with the ensuing blaze destroying the drilling rig. There were no casualties, but fire was not brought completely under control until 38 days after the initial explosion, by which time around 28.3 Mcm of gas had been consumed in the fire (Ward et al., 2003).

9.1.4 Summary/discussion

As alluded to, underground fuel storage facilities in California account for 11 of the documented problems in this category. California represents a special area for a number of reasons:

- It is a highly petroliferous area, developed in (relative to the UK) young (Cainozoic) sedimentary rocks
- It is an area of ongoing seismic activity. The area is undergoing compression related to plate tectonics, which is associated with transpressional tectonic forces. This has resulted in the formation of many anticlinal traps with numerous surface rupturing faults that have contributed to fracturing of strata over of large areas
- It has a long history of (often unregulated) oil exploration dating back to the late 1800s, with many thousands of wells having been drilled across the State, often of very high density
- As a consequence, the locations of many wells are not known accurately, with many not known at all. Also, many of the older wells now have no, or at best old and deteriorating, well completions (casings and cement)

Consequently, California provides a high number of incidents associated with UGS and distorts the data. Whilst data provide important information on problems encountered and modes of failure of UGS infrastructure for planning and risk assessment, many of the problems and geological factors encountered in California would not necessarily be applicable or relevant to assessment of UGS in the UK situation.

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9.2 DOCUMENTED CASES OF PROBLEMS OR INCIDENTS AT AQUIFER FACILITIES

Underground gas storage operations in an aquifer were first undertaken in 1946 at a site in Kentucky, USA (Chabrelie et al., 1998; Favret, 2003) and there are currently about 80 operational aquifer storage facilities in the world today. Most of these are in the United States, the former Soviet Union, France, Germany and Italy.

This study has identified 17 documented problems and incidents at aquifer storage facilities (Tables 7&9). Two incidents (c. 12% overall), both in Europe provide the only fatality, casualties and evacuees at aquifer storage sites: Ketzin and Spandau, both on the outskirts of Berlin in Germany. Relative to today's number of operational facilities (80), which are fewer in number than in recent history, the 17 reported incidents represents an incident rate of c. 21%, with cases involving fatalities/casualties representing 2.5% (Tables 2, 7&9). All involve injection and storage of natural gas, with 12 (c. 71%) having occurred in the USA, of which, 8 (c. 47%) have been in Illinois (Buschbach & Bond, 1974; Coleman et al., 1977; Perry, 2005). To date, 5 documented incidents (c. 29%) have occurred in Europe (at Stenlille in Denmark, Chémery in France and Spandau, Frankenthal and Ketzin in Germany).

Two incidents in Europe resulted in the reporting of the only fatality, casualties and evacuees at aquifer storage sites. Sketchy reports exist for an incident, at Ketzin around 25 km west of Berlin in Germany (refer Appendix 5). During the 1960s, town gas was being stored underground in an aquifer, when leakage led to the seemingly permanent evacuation of the village of Knoblauch (New Energy News, 2007; Kanter, 2007; MyDeltaQuest). These reports mention that leakage of carbon monoxide (CO) was also associated with the leak (MyDeltaQuest), which is believed to

have led to 1 fatality as a result of CO having come up an old well into a house. The well was repaired and sealed following the incident (N.J. Riley pers comm., 2007) and natural gas continued to be stored in the anticlinal structure from the 1970s until 2000, when the facility closed, leaving only cushion gas in the aquifer. The stored gas was thought to have been escaping through the cap rock, perhaps aided by the presence of faults, as a gas chimney is associated with one important fault zone in the crest of the structure (see e.g. Juhlin et al., 2007).

A second incident occurred at Spandau, in the western suburbs of Berlin (Germany) on April 23rd 2004 (Associated Press, 2004; Berliner Zeitung, 2004a,b&c). At about 9.40-9.45 am, an explosion destroyed part of the wellhead of a monitoring well (B5). This allowed the escape of gas that ignited, resulting in a flame about 30 m high. The gas escaped for about a day before it was brought under control. The explosion destroyed a tanker truck and damaged several buildings at the gas storage site, leaving 9 injured, 3 seriously. It led to the evacuation of around 500 people within 1 km of the site (F. May, pers. comm., 2004). Although maintenance work was being carried out, involving H_2O_2 treatment of the well following winter operation at the time, the cause of the incident is unclear (F. May, pers. comm., 2004). Work on the contents gauges at the facility was also ongoing at the time and failure of a seal is thought to be a possibility. At no time was the stored gas inventory in danger (GASAG, 2004).

Problems with, or failure of, the well or casing (due to cracks, damage, corrosion or during repair/maintenance), was involved in 3 (c. 18%) of the documented cases. Two have been in Europe, at Stenlille, Denmark (well casing - Laier & Øbro, 2004 & this volume) and at Chemery, France (during routine maintenance of a well completion and replacement of a filter - NAWPC, 1999; IAVWOPSG, 2005). The third was at Leroy, Wyoming (USA), where gas leakage was linked to corroded casing and overpressuring of the aquifer (Katz & Tek, 1981; Araktingi et al., 1984; Nelson et al., 2005). At a facility in Northern Indiana, the reservoir/structure leaked gas (Buschbach & Bond, 1974; Perry, 2005). Unlike some of the leaking fields that utilize shallow gas capture through shallow wells before the gas can reach the surface, this field (at approximately 457 m) was deemed too shallow for this type of procedure and was abandoned (Kent Perry, 2007 pers comm.).

In terms of the difficulties encountered at other facilities, problems with the cap rock provided the main 'failure' mechanism and all such leakages occurred at facilities in the USA. It was found that in 9 (c. 53%) of the cases, gas had migrated to shallower levels due mainly to the predicted caprock not having been gas tight. In 3 (c. 18%) of those cases, faulting of the caprock is also thought likely to have been a contributary factor in the migration of the product from the reservoir (Jones & Drozd, 1983; Jones & Pirkle, 2004; Morgan, 2004).

9.3 DOCUMENTED CASES OF PROBLEMS OR INCIDENTS AT SALT CAVERN GAS STORAGE FACILITIES

Large underground salt caverns provide secure environments for the containment of materials that do not cause dissolution of salt. As outlined in Chapter 2, salt caverns have been used for the storage of a range of materials including liquid (oil, liquified petroleum gas [LPG] and NGL's), gaseous hydrocarbons and hydrogen. However, this study has found evidence for 27 reported problems at salt storage facilities. Relative to today's number of operational facilities (66), which are fewer in number than in recent history, the 27 reported incidents represents an incident rate of c. 41%, with cases involving fatalities/casualties (5) representing 7.6% (Tables 2, 7&10).

In terms of the main failure mechanisms or difficulties encountered at salt cavern storage facilities, problems with, or failure of, the well or casing (due to cracks, damage, corrosion or during repair/maintenance), was involved in 11 (c. 41%) of the 27 documented cases (Tables 7&10). Of these, 4 (c. 15%) well-related incidents (Hutchison, Brenham, Mont Belvieu and West Hackberry) led to 8 fatalities (Fig. 25). Failure of above ground infrastructure was involved in 5 (c. 19%) of the incidents (valve, pipes, wellhead or compressor units). They represent the highest

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rate of failure of this nature in all storage facility types and resulted in 3 fatalities at Brenham. Three facilities were brined but never commissioned, one at Bayou Choctaw (Louisiana) failed due to uncontrolled leaching. Problems were encountered at the Clovelly and Napoleanville (Louisiana) sites, due to insufficient site characterization, with the caverns being built too close to the edge of a salt dome and encountered 'host rock' in the cavern walls (Neal & Magorian, 1997).

Large volume losses occurred in caverns at 3 facilities (c. 11%): Eminence, Louisiana (Allen, 1972), Kiel in Germany (Coates et al., 1981; Bérest & Brouard, 2003) and Tersanne in France (Thoms & Gehle, 2000; Bérest & Brouard, 2003). The Eminence facility operated for over 10 years, but the loss of cavern capacity due to having operated at pressures too low to maintain cavern walls, appears to have led to its closure in the early 1980s. However, operations appear to have resumed, with cavern volume having been regained by further brining operations (Warren, 2006). The Tersanne facility, one of a number of caverns operated by Gaz de France in southeast France, remains operational having also recovered much of the original volume loss (Thoms & Gehle, 2000; Warren, 2006). Kiel has continued operating, storing town gas since 1971 (Padró & Putsche, 1999).

Two incidents involving storage of LPG, at Brenham, Texas (NTSB, 1993a&b, 2006; Thoms & Gehle, 2000; Gruhn, 2003) and Petal, Mississippi (AEA, 2005), arose from overfilling of the caverns and must again be deemed the result of human error. Both were operated in brine compensated mode, which if poorly monitored and controlled, can lead to further undetected enlargement of the cavern and inaccuracies in storage volumes. A third incident where a propane storage facility was operated in brine compensated mode occurred at Mineola, East Texas (USA) in 1995 led to a release of propane and an explosion followed by a fire (Gebhardt et al., 1996; Bérest & Brouard, 2003; Warren, 2006). Here, communication between 2 caverns resulted from the injection of brine during each cavern emptying-filling cycle, which dissolved the salt wall between the 2 caverns, causing structural weakness and ultimately failure (refer Appendix 5). The accident was, therefore, the result of human error on at least two counts. Firstly, enlargement of the caverns and a narrowing of the intervening salt wall by the injected brine went unnoticed. Secondly, one cavern was held at much lower pressure than the adjoining one, which resulted in pressure induced failure of the thinned intervening cavern wall (Bérest & Brouard, 2003; Warren, 2006).

A number of cavern storage sites exist in and around Conway (Kansas, USA) storing NGL's, some of which have operated since 1951 (Ratigan et al., 2002). One NGL storage facility in the area has experienced sustained leakage of product from caverns, possibly since 1956. NGL's and gas have been encountered in both storage wells and domestic wells on at least 6 separate occasions between 1980 and 1981. In December 2000, NGL's were encountered in a newly drilled well at the site (Ratigan et al., 2002). Investigations have shown that large parts of the Conway area are affected by salt dissolution (wet rockhead). This has led to the development of collapse breccias forming voids with wells losing circulation at the top of the salt and into which hydrocarbons have migrated (Ratigan et al., 2002). Investigations into the leaks and possible remedial action are ongoing.

9.3.1 Discussion

Two cases of problems encountered at salt cavern facilities (Clovelly and Napoleanville, Louisiana) were due to insufficient site characterization, with the caverns having been built too close to the edge of a salt dome such that there was not enough salt 'buffer'. In terms of the UK, this is not really an issue onshore, as there are no halokinetic structures. However, it would have similarities where a previously unknown large fault, producing an offset of the bedded salt deposits, might be close by a proposed facility, with the potential to intersect or impact on the cavern walls. Over much of the workable salt beds area onshore in the UK (mostly the Cheshire Basin, but including Wyre in Lancashire), exposure of rocks at surface is often poor, with thick

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glacial drift deposits blanketing the bedrock (solid) geology. A lack of exposure and also subsurface information in terms of boreholes and/or seismic reflection data, mean that surface geology is not, therefore, always well constrained. It is possible that site characterization (subsurface mapping etc. using high resolution seismic reflection data for example) may not yet have been adequately undertaken and that possible faulting of an area is as yet poorly constrained or even unrecognized.

Consequently, it might be expected that detailed site characterization would be required to adequately delineate not only the extent of the salt body (and structures affecting it) in which gas storage is proposed, but also its physical properties. This could include acquisition of seismic reflection data of high enough quality (resolution) to image the main structure and any faults present.

The Clovelly and Napoleanville examples could have more relevance in the offshore environment, where thick Zechstein and Triassic salt deposits occur. The offshore area is not the subject of this report, but is worthy of note as the Government is considering the prospects for offshore UGS, that would include salt cavern facilities. In the East Irish Sea and particularly the Southern North Sea, halokinesis has given rise to large salt structures (pillows, domes and walls) that could offer sites for storage caverns. The Government is currently considering the feasibility of such schemes and revisions that would be required to current legislation related to storing gas in offshore areas (Smith at al., 2005; DTI, 2006c&d, 2007).

9.4 DOCUMENTED INCIDENTS AT ABANDONED MINE FACILITIES

Few hydrocarbon storage facilities exist in abandoned mines (Table 2), with 4 documented problems and incidents at abandoned mine storage facilities having been identified. Together with an incident that occurred at what is described as an unlined rock cavern facility, this category of storage represents about 8% of overall UFS incidents (Tables 7&11). Of the 2 facilities where natural gas was being stored in abandoned coalmine workings (Leyden, Colorado - Raven Ridge Resources, 1998 and Anderlues in southern Belgium - Piessons & Dusar, 2003), problems with leakage through the caprock or overburden was encountered. Leyden ceased operations in 2001 and was converted for water storage, whilst at Anderlues, gas storage operations began in 1980 but ceased in 2000, due to connectivity with shallower mine levels, and leakage through the caprock.

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A third facility, at Weeks Island, Louisiana, was developed in an old salt mine, storing crude oil as part of the American Strategic Petroleum Reserve (SPR). The facility experienced problems associated with wet rockhead and sinkhole formation that ultimately caused the withdrawal of the stored oil and its closure (Neal & Magorian, 1997; Warren, 2006).

A fourth facility at Crossville (Illinois) is believed to have been a former coalmine, storing propane at a depth of around 60 m. The facility experienced leakage to surface over most of its 30-year life (Pirkle, 1986, Pirkle & Price, 1986, Jones & Burtell, 1994). In 1981-1982 investigations revealed that product escaped from storage via the mineshaft and one of the mine drifts (tunnels). Migration within the overburden was pressure driven along faults, fractures and joints (Pirkle, 1986; Pirkle & Price, 1986; Pirkle & Jones, 2004).

Brief details exist of a product release incident on 24 August 1973 at what was described as an 'unlined underground cavity' at the Ravensworth Propane Storage Facility (Berest, 1989; N Riley, HSE pers com 2007). The facility is presently operated by Washington Gas Light Company and believed to be in Virginia, USA. The propane was stored in an unlined underground cavity (which is inferred to be a salt cavern, although this has not been confirmed), around 130m below ground level with a capacity of approximately 50,000 m^3. Cavern operations continued whilst water was injected in the vicinity of the well in an attempt to stem the emissions. The latter point would indicate that the storage rock is not in fact salt.

9.5 FREQUENCY RATES OF NATURAL GAS STORAGE INCIDENTS AND INCIDENT FREQUENCIES FROM OTHER STUDIES

This study has described problems at 65 UFS sites, however, a lack of information relating to many of the 65 problems described above means that at this stage, information on the number of wells at any one site, the years of operation/downtime or exact opening/closure date is not available. It is, therefore, difficult to determine the incident rates relative to 'storage experience', either as the total operational hours of gas storage against number of incidents, or the total operational well hours against the number of incidents.

A report by the Ohio Environmental Council (2006), attempted such estimates during an assessment of the potential for underground storage of CO_2 (Lippman & Benson, 2003; Perry, 2005). These figures are, however, related to US storage facilities and are not worldwide figures. The report states that such experience amounts to in excess of 10,000 facility years and demonstrates that operational engineered storage systems can contain methane with release rates of 10^{-4} to 10^{-6} per year.

A recent review of documented data from the 1970s onwards, which only identified 17 accidents associated with fugitive gas emissions from natural gas storage facilities, provides operational figures incorporating facilities outside the USA (Papanikolau et al., 2006). The review of incidents, whilst more restricted than in this report, is nevertheless useful. It provided the cumulative operative years of natural gas storage sites, which were calculated to be 20,271 years with well operations to be 791,547 well-years. Of the incidents identified, 1 occurred during maintenance of surface equipment and was not included in the natural gas storage leakage frequency calculation. The remaining 16 were associated with underground causes (principally, well failures).

The incident frequencies associated with these facilities were then calculated, showing:

- The frequency of a major incident from a natural gas storage facility was 8.39×10^{-4} /site/yr, or once every 1,192 years of site operation.
- The frequency of a major incident from a natural gas storage well was 2.02×10^{-5} /well/yr, or once every 49,505 years of well operation.

These results were compared with a smaller sample European study (MARCOGAZ; Joffre & LePrince, 2002), where the accident frequency from well failure was calculated as 5.1×10^{-5} accident/well/yr (see section 9.5.1). By comparison, a study of blowouts from oil and gas reservoirs offshore revealed a production blowout frequency of 5×10^{-5} per well/yr, or a major gas release from a well once every 20,000 well-years (Holand & Holland, 1997; Papanikolau et al., 2006).

9.5.1 The MARCOGAZ European UGS Study

In 1998, an ad hoc working group was established by MARCOGAZ to exchange information on UGS operations. This work was essentially dedicated to the survey of the consequences of some EC Directives:

- The COMAH Directive (Control of Major Accidents Hazards involving dangerous substances) or SEVESO II Directive (Dir. 96/82 of 12/9/1986) to be applied by Member States from February 1999
- The Water Framework Directive (Directive 2000/60/CE of 23/10/2000) establishing a new policy in the field of water and replacing the existing Groundwater Directive 80/68 of 17/12/1979).

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At a meeting in 2000 with the participation of 8 companies involved in UGS activity (DISTRIGAS, DONG, ENAGAS, ENI-AGIP, Gaz de France, ÖMV, RUHRGAS and TRANSCO), it was decided to establish a database for major accidents on UGS facilities based upon the COMAH Directive, namely, that "The scope of the COMAH Directive concerns some industrial activities using dangerous substances. Natural gas is one of these substances so that UGS and LNG terminals are concerned with the COMAH Directive regarding two thresholds, which correspond to 50 t and 200 t of natural gas." The purpose of the database was to "help to prove to the public and to national authorities the high safety level of UGS, to dissipate fears of people bordering of UGS sites and to contribute to reducing the requirements of authorities by implementing the SEVESO II Directive in each national Law system."

The database was established (Joffre & LePrince, 2002) and contains information from each company involved in the UGS Working Group. The accidents included in this database were selected using the criteria defining major accidents and given in Annex VI of the COMAH Directive. The criteria can be summarized as follows:

1. Fire, explosion or accidental discharge involving at least 10 tons of natural gas (5% of 200 tons).
2. One death or,
   - injuries inside establishment or,
   - 1 injury outside establishment or,
   - housing damaged or made unavailable outside establishment or,
   - evacuation or confining of people for more than 2 hours (persons x hours <= 500) or,
   - interruption of drinking water, electricity, gas or telephone supply for more than 2 hours (persons x hours <= 1000)
3. Effects on environment
   a. permanent damage: 0.5 ha of a protected area or 10 ha of a larger area
   b. significant damage: 1 ha of a groundwater aquifer
      10 km or more along a river
      1 ha or more of a lake
      2 ha or more of a coastal area or sea
4. Material damage
   a. More than 2 Million Ecu inside establishment
   b. More than 0.5 Million Ecu outside establishment
5. Transboundary damage

In total, 7 companies responded covering 7 European countries (Table 12; DISTRIGAS, DONG, ENAGAS, ENI-AGIP, Gaz de France, ÖMV, RUHRGAS), with 11 reports of major accidents produced from 3 of the 7 participating companies. Four of the 7 companies, therefore, had no major accident despite the fact that 1 of these 4 has a very important set of UGS sites. Furthermore, only short report forms were returned by 2 companies (due to loss of information from older incidents), which meant that only limited information is available for some incidents, thereby limiting analysis.

The scope of the database for UGS is concerned with all parts of the infrastructure at storage plants, i.e. wells, compressors, treatment & measuring facilities and pipework systems that have led to any particular incident. The breakdown of the information collected during the MARCOGAZ survey of European UGS incidents to 2000 is provided in Table 13 (after Joffre & LePrince, 2002).

At the time, the 7 companies participating in the UGS MARCOGAZ survey were operating 42 UGS sites with 845 wells (corresponding to 77% of UGS wells in EU at the time), with a total of

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970 cumulated years of operation at these sites (Table 12). The calculated average number of cumulated years of operations for the wells at these sites is 100,155 (based upon half the number of wells over the entire life of the sites, which is thus thought to be a minimum.

The survey results revealed:

- 6 accidents occurred due to surface processes over a cumulative period of 970 years, the probability for major accidents on surface facilities of UGS sites was thus calculated at $6x10^{-3}$ accident/year/site
- 5 accidents occurred due to wells over a cumulative period of 100,155 years, the probability for major accidents on wells of UGS sites was thus calculated at $5x10^{-5}$ accident/year/well
- 1 accident occurred that resulted in severe injury due to well problems over a cumulated period of 100,155 years, the probability of major accidents resulting in severe injury on wells was thus calculated at $1x10^{-5}$ accident/year/well

The main conclusions of the MARCOGAZ European UGS study (Joffre & LePrince, 2002) were:

- The frequency (i.e. number of accidents divided by the number of operative sites) was about the same during the 1970s and the 1980s, but about half that during the 1990s. This was interpreted as indicating that the safety level of UGS facilities improved due to increased experience and the additional measures taken by operators following these events
- The major hazards leading to accidents on UGS facilities arise from surface processes (P = $6x10^{-3}$ accident/year/site) with no accident resulting in severe injury reported. Safety measures for surface processes are, therefore, related to a regulatory framework that has now operated in each Member State for a long time
- For wells, despite one accident resulting in severe injury, the probability is much lower (P = $5x10^{-5}$ accident/year/well for all types of accidents and P = $1x10^{-5}$ accident/year/well for accidents with injury)
- The frequency of all types (wells and surface process) had decreased by about half during the last 10 years
- Except for 2 accidents causing injuries, all other cases of accidents were classified "major accident" because of the release of gas or material damage inside the UGS facility
- No death inside or outside the UGS facilities were reported
- No injuries outside the UGS facilties were reported
- No material damage outside the UGS sites was reported

The MARCOGAZ European UGS study represents an important, but limited source of information. It claims there have been no deaths inside or ouside a UGS facility, yet does not contain reference to the Ketzin incident during which there are reports of 1 fatality (NJ Riley, 2007 pers comm. - section 9.2 and Appendix 5).

9.5.1.1 RELATIONSHIP OF THIS STUDY TO THE MARCOGAZ SURVEY

This study has presented evidence of 12 incidents in Europe relating to UFS between the 1960s and 2006: 1 at a coalmine, 2 at depleted fields, 5 in aquifer facilities and 4 at salt cavern storage facilities (Tables 7-11). However, the responses of 7 gas storage operators (Joffre & LePrince, 2002) suggests that there is evidence of a number of other incidents (Table 12). Precise details are not readily available, but 11 incidents of varying severity to 1998 were reported, i.e. predating the Spandau (2004), Breitbrunn/Eggstatt (2003) and Rough (2006) incidents and involving natural gas (7), oil (3) and solid (1) storage. This would imply there are at least 2 incidents not widely reported or included in this study. Reported casualties from these 11 incidents numbered 4, one serious, with no deaths. The suspected causes were related to human error (3) or

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plant/equipment (8). In all cases, the immediate source of the accident was either problems with wells (5) or surface process (6: Joffre & LePrince, 2002).

Except for 2 accidents causing injuries, all other cases of accidents in the MARCOGAZ study (Joffre & Le Prince, 2002), were only classified as a "major accident" because of release of gas or material damage inside the facility. Importantly, of those incidents reported, no injuries or material damage occurred outside the storage facilities. Importantly, therefore, neither the MARCOGAZ nor the Papanikolau et al. (2006) studies appear to have identified or reported the apparent death at Ketzin (Germany) in the 1960s.

Failure of the well as the main cause of product release is supported by a smaller study of fugitive gas emissions from natural gas storage facilities (Papanikolau et al., 2006). It was also noted that in both the USA and Europe the incidents of well failures were similar in the 1970s and 1980s but decreased significantly in the 1990s. This decrease is interpreted as being due to improved technology, better operational practices and regulatory improvements (Papanikolau et al., 2006). It may just be, however, that there has also not been time for the faults or problems with younger wells to surface.

9.5.2 Incidents known by the Risques du Sol et du Sous-sol Directorate

Storage of gas underground is undertaken on the outskirts of Paris and BGS has been advised of a conversation between Dr N Riley (HSE) and Mr M Ghoreychi (Directeur des Risques du Sol et du Sous-sol). The conversation at an INERIS seminar on 9th May, 2007, related to reports of a number of leaks from storage at one or more of these facilities, some of which have involved the loss of very large quantities of gas. Mention is made of the gas having leaked from shallow 'caverns' at 80 metres depth near Versailles.

The details are very sketchy and efforts to contact Mr Ghorechyi have, to date, proved unsuccessful. However, the report of 'caverns' would imply salt caverns at very shallow depths, or perhaps lined rock caverns. However, preliminary consulations of French 1:50,000 scale geological maps for the Paris-Versailles region indicate that whilst gypsum is present in the Paris Basin, there is no mention of halite beds. This is borne out by Ziegler (1990). Furthermore, the depths seem too shallow for salt cavern storage (given the potential for wet rockhead development etc.) and mention is made of the leakage having been controlled by water injection, which again would seem highly unlikely in a salt-bearing sequence.

The likelihood is that the leakage occurred from storage facilities developed in relatively shallow aquifers (probably with poor caprock lithologies), like the nearby Beynes gas storage facility, operated by Gaz de France. This is situated 25 km east of Versailles, in open farmed countryside and is surrounded by several small villages. It consists of 2 underground storage reservoirs, the Beynes Superieur (commissioned in 1956) and the Beynes Profond (commissioned in 1975), both of which are aquifers, at somewhat greater depths of 405 m and 740 m respectively (http://www.ieagreen.org.uk/nov69.html). It is not clear if the leakages mentioned were reported in the MARCOGAZ survey (previous section). Because of this, the late awareness of the incidents and the sketchy details available, these reports are not included in the database of reported incidents (sections 9.1-9.4).

Gas losses might be expected in shallow aquifer storage due to the increased pressures on the caprock, which may not perform aswell as one in an oil or gasfield. However, this does not mean that the gas would necessarily reach the surface or pose a hazard, as witnessed by the examples from Indiana, where leakage is monitored and controlled and which, to date, do not appear to have led to any reported casualties.

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9.5.3 Summary and discussion

This study has identified only 65 documented incidents or problems related to UFS facilities, with reported totals of only 9 deaths, around 62 injured and circa 6700 evacuees (not including the evacuated village of Knoblauch, near Berlin). As detailed above, 8 of the fatalities have been sustained at UFS (not just UGS) in salt caverns or abandoned salt mines with up to 3 deaths at individual sites. A ninth fatality appears to have been linked to leakage of gas and CO at an aquifer storage facility in the 1960s. Of the incidents related to underground storage of hydrocarbons described here, 15 were accompanied by an explosion and/or fire, 10 at salt cavern facilities (Table 7). It is noted that these figures probably represent a minimum as there are no statistics from Russian or East European facilities (where it is thought likely that there have been incidents, but that they have not been reported or found during this study). However, given the sensitive nature of the topic and people's fear of UGS, it is surprising that if they have occurred that they have not been more widely reported. Major accidents with casualty rates are regularly reported from other areas of the energy supply sector (Chapter 10) and one would think that UFS would be no different in attracting public attention or press reports, which would then have been reported in the literature.

The majority of problems have occurred at salt cavern storage facilities (27), where 9 have led to fatalities, injuries or the evacuation of people and 10 have been accompanied by an explosion and/or fire. Eight of the 9 reported deaths at UFS facilities have occurred at 4 salt cavern storage incidents and involved storage of various hydrocarbons, not just natural gas. In all cases the salt cavern(s) did not fail, although the Mineola (USA) incident that led to release of propane and an explosion arguably involved failure of the caverns (in that there was catastrophic communication between caverns). In actual fact the failure is ultimately attributable to human (operational) error in that the amount of ongoing leaching of the caverns during the brine compensated storage operations that led to the thinning of the intervening saltwall was not recognised. All other causes have been related to human error, poor management or operational practices, utilisation of existing and inappropriate brine caverns, poor forward planning, a lack of due diligence by the storage company or operator, or a combination of these factors (see also Warren, 2006). It should be noted that the earliest salt cavern storage sites utilised old brine caverns not ideally designed and engineered for gas storage. The first purpose-designed and engineered gas storage caverns were not constructed until the early 1970s. Technology and understanding of salt rheology and cavern design has increased significantly since those early days of cavern design and construction.

The second highest rate of incidents is found in aquifer storage facilities (17), which are associated with 1 reported fatality from incidents at aquifer storage facilities, with only one other incident (Spandau) having resulted in injuries (9), all onsite. Following the leak at the Ketzin facility in the 1960s, the village of Knoblauch near Berlin (the then DDR) was evacuated, apparently permanently (MyDeltaQuest). Depleted oil and gas fields provide the most widely developed type of facility, with about 478 in operation, mostly in the USA. The 16 incidents found at these storage sites have, to date, led to only 5 injured with no reported incidents involving deaths. Hopper (2004) is correct to state (when discussing catastrophic loss of stored product) "In every case, however, a salt cavern storage facility was the culprit, not a depleted reservoir or aquifer gas storage facility". However, he is describing single point (catastrophic) failures at salt cavern facilities and the statement could be misleading, as Tables 2 and 7 document stored product (fuel) loss and casualties at depleted reservoir, aquifer and abandoned mine fuel storage facilities related to causes other than single point catastrophic failure.

Closer examination of the statistics shows that 53 of the 65 incidents and problems with UFS have occurred in the USA (Table 7). Of these, 12 have been in California, with 10 each in Texas and Illinois, where in the latter, 9 have been associated with pore storage (the other was leakage of propane from an abandoned mine). California provides a very different environment to that of the UK in a number of significant respects. Firstly there are many more poorly located wells

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stemming from a long history of relatively unregulated oil exploration. Secondly, it is a tectonically very active area, with present day seismic activity and major faults causing surface ground rupture. Many of the oilfields are compressional features formed during Cainozoic times with associated faulting of the reservoir and caprock units causing ongoing leakage from the reservoirs and in one case, fracturing of a well. By comparison, the UK lies in a seismically inactive intracratonic area, where the possibility of any fault reactivation causing a direct rock rupture hazard at surface anywhere in the UK is all but negligible. Such an event has not happened since historical times (and perhaps since Quaternary times, up to 1.8 Ma) and known larger UK earthquakes have depths considerably in excess of their rupture dimensions (Musson in Evans et al., 2005 – section 6.2).

Old and abandoned wells represent a major source of potential leakage in any UGS environment, which is particularly so in the Californian oilfields, especially in the Los Angeles region (e.g. Chilingar & Endres, 2005). Steel well casings and cement deteriorate over time, resulting in shoe leaks and loss of bonding in the annular cement, permitting gas to enter the well and leak to the surface. Due to poor construction practices and deterioration over time, old wells are especially prone to the development of leaks. However, even when plugged in accordance with contemporary government regulations, most abandoned oil and gas wells eventually develop leaks, with failure rates of 10% known in recently plugged wells in California due to the use of inferior materials by contractors during well abandonment (Miyasaki, in press). But even modern up-to-date cements do not guarantee success, with failure rates of 10-15% documented (Marlow, 1989; Chilingar & Endres, 2005; Miyasaki, in press), and the figure may be as high as 60% in some areas (Miyasaki, in press). A further problem exists with completed oil/gas wells in depleting fields. These wells have generally been operating in a declining pressure regime as the field becomes depleted. Re-injecting gas back into the reservoir raises the pressures on the existing completions and casings, providing the potential for failure, which may be exacerbated if injection and withdrawal cycles are rapid. Old well completions have, therefore, to be the focus of detailed pressure and sample tests before the facility is fully commissioned. Understanding these failures requires knowledge of the history, nature and purpose of the wells, the brining methods (if related to brine caverns) and the ultimate operation of the wells, particularly in salt caverns.

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From the reviews of each incident above and in Appendix 5, it is clear that in the vast majority of cases, the incident or problem experienced at any particular facility has not been the result of a direct failure of the geology. The exceptions, where the geology has apparently been linked to the failure are:

- one salt cavern facility, where connection of caverns occurred (Mineola, USA), although human error was ultimately behind this failure
- a case where a gas storage well in California appears to have been crushed due to faulting (in a seismically active area, with little similarity to the UK environment)
- in a number of aquifer storage sites, mainly in Illinois (USA), where the caprock was not gas tight and may have also been affected by faulting. In these examples, human error seems more appropriate in that gas tightness of the caprock was not established. Aquifer storage is not, however, a type of storage facility currently under review in the UK
- and in a number of depleted oil/gasfield storage sites, mainly in California (USA), where the cap rock was not gas tight and may have also been affected by faulting. Again, these occurred in oilfields developed decades ago in a seismically active area, where fault rupture at surface is known on faults that are described as active, which is not the case in the UK. Again, human error seems more appropriate in that 'leaky' structures were put into use for storage purposes

Instead, in incidents most relevant to UK developments, poor engineering practices, a lax regulatory regime and mismanagement appear to have been the main factors in release of stored

product. Most of the main UGS incidents have occurred in the USA, where regulations and well records have not been carefully controlled or maintained. There has been failure of either the man-made infrastructure (well casings, cement, pipes, valves, flanges, compressors etc.), or human error, which has included overfilling of caverns, inadvertent intrusion and poor site characterisation including not establishing the gas tightness of the cap rock. The causes, scale, and severity of the accidents are also extremely variable and have in some cases been the result of a combination of these factors. Problems have also arisen from (extreme) natural events (seismic activity).

The main question is, therefore, to what extent can these UGS facilities be made safer? Moss Bluff, as in most currently operating salt cavern facilities, had only 1 well for injection and withdrawal (Hopper, 2004). A single well system does not generally cause a problem until a wellhead or valve failure occurs and a gas leak and fire ensues. Moss Bluff typified this when high pressure gas was vented and burnt at such high temperatures that it was impossible to reach the remaining gas stored and contain the leak and fire. A future requirement and safety mechanism, especially useful when the cavern is full and fully pressured, may be for a back up well or wells remote from the other, which would permit safe withdrawal of the stored gas and prevent most of it from being lost in a fire. Costs generally dictate that salt cavern developers rarely incorporate such 'redundancy' (Hopper, 2004).

In contrast to salt cavern storage, depleted reservoir storage typically has a number of wells used for injection/withdrawal purposes. There are also likely to be a number of former exploration and production wells across the oil/gasfield. In the worst-case scenario of a well being lost or damaged at a depleted reservoir, then these wells provide effective 'inbuilt' back-up wells capable of withdrawing (to safe levels) the remaining gas in store, and then for only as long as it would take to cap the well in question (Hopper, 2004). Gas loss would be limited in depleted reservoirs as storage wells are easier to cap if they were to blow out and drain only a limited area of the reservoir. Also releases are likely to be somewhat slower due to the physical constraints of the gas being 'produced' from pore spaces.

The aspects of gas release and flux rates for differing storage scenarios are investigated in the accompanying Quintessa report (Watson et al., 2007).

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10 Incidents and casualties in the oil and gas production/supply chain and petrochemical industries

Chapter 9 reports a number of incidents of varying severity have occurred at UFS facilities. Tragically as noted, a small number (5) of these have involved accidents that have left 9 dead (Table 7). However, fatalities have occurred in other sectors of the oil and gas industry and energy supply chain, and it is estimated that during the period 1970-1985, 25% of the fatalities in severe accidents worldwide have been in the energy sector (Fritzsche, 1992; Hirschberg et al., 2004). This section, therefore, aims to provide an assessment of the relative numbers of casualties elsewhere in the energy supply chain, including exploration, extraction and refining, transport to and from a refinery, end user incidents including regional and domestic supply/delivery and industrial accidents in the petrochemicals industry (Tables 15-20; summarised in Table 14). Such figures permit a comparison between, and help put into perspective, the casualty figures resulting from the UFS sectors.

The following brief account of casualty figures from published worldwide major accident statistics in the oil and gas production, transport (pipeline, train, tanker) and supply sector for the period 1969-1996 (Table 14) is based upon Hirschberg et al. (1998, 2004) and Papadakis (1999). It should be noted that in their studies, incidents qualified when there were 5+ deaths, 10+ injuries or 200+ evacuees. Additional sources provide data concerning incidents post-dating 1996 (see references in Tables). The list of casualties in Table 14 is, therefore, neither exhaustive nor full, but is a minimum that represents the more severe accidents for which figures are available.

For this reason, statistics relating to hazardous liquid and (domestic) gas supply (distribution) pipeline incidents published by the USA and UK governments (respectively, Tables 15; http://ops.dot.gov/stats/stats.htm and 16; http://www.hse.gov.uk/gas/domestic/statistics.htm) are also presented for the period 1986-2005. These data are shown independently to the figures in Table 14, not only because there could be some duplication in the numbers if added together, but in order to maintain the integrity of different data sources and to illustrate individual countries and types of pipeline incidents. In addition, figures are also summarised for significant petrochemical plant incidents, hydrocarbon related railroad accidents in the USA and above ground storage vessels that have involved death or injury (refer http://www.ntsb.gov/).

10.1 CASUALTY STATISTICS IN OTHER AREAS OF THE ENERGY SUPPLY CHAIN

Worldwide casualty figures arising from areas of the energy chain, involving the production and supply of oil, gas and LPG is illustrated in Table 17. It shows that in total, there have been at least 21,629 fatalities, 46,606 injuries and 1,341,533 people evacuated during incidents. The highest fatality rates have occurred in the oil sector, with over 15,695 deaths of which at least 13,000 occurred during the transport to the refinery and in the regional distribution stages. These are, therefore the most risk-prone stages in the oil chain, where higher oil consumption leads to a greater number of severe accidents resulting in fatalities (Hirschberg et al., 2004). Three major accidents occurred in 1980, 1982 and 1987 (Hirschberg et al., 1998) and illustrate the significantly higher number of casualties arising at individual incidents elsewhere in the energy supply chain. The first in January 1980 resulted from a well blowout off the Nigerian coast, causing the most number injured during one oil related event (3,000, plus 180 dead). The second in 1982 was caused by the collision of a Soviet fuel truck with another vehicle in Afghanistan, which led to 2,700 fatalities (including Soviet soldiers and Afghan civilians, though not as a

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result of acts of war). The third occurred off the coast of Mindoro in the Philippines, with 3,000 fatalities.

In the gas supply chain, the yearly number of LPG and natural gas severe accidents increased significantly after 1970 and then showed a general decrease after 1980-1984. The worst years in terms of the number of fatalities were 1984 and 1989 for LPG and 1978 and 1982 for natural gas (Hirschberg et al., 1998). The stages in which the greatest number of casualties occurred are (Table 17): 'long distance transport', 'local distribution' and 'regional distribution' for natural gas and 'regional distribution' for LPG.

Casualties in the LPG sector totalled around 3,700 dead, 21,120 injured and almost 1 million evacuated. Over 53% of fatalities involving LPG occurred during the regional distribution stage (transport by road or rail tankers, pipelines or by ship – Table 17). The dominant cause was impact failure (Hirschberg et al., 2004). Two of the (then) world's largest industrial accidents involved LPG (Hirschberg et al., 1998). The first occurred on November 19th 1984 in San Juan Ixhuatepec in Mexico, when about 500 were killed, 7,231 injured and 200,000 were evacuated following the leakage of LPG from a storage vessel, which then ignited. The ensuing explosion and fire destroyed 50 of the 54 storage vessels in the depot (Hirschberg et al., 1998). The second major incident occurred on 4th June 1989 when around 600 people were killed and at least 755 were injured by a massive explosion and fire when sparks from a passing train ignited a gas cloud from a leaking pipeline nearby, which was carrying 30% gasoline and 70% LPG between Asha and Ulfa in Siberia, Russia. An LPG related incident at Mississauga (Canada) on November 11th 1979 led to the evacuation of around 220,000 people due, in part at least, to the presence of chlorine in the rail tanker fire.

Casualties arising from the production and transport of natural gas amount to over 2,230 dead, 5,210 injured and 105,011 evacuated (Table 17), 40,000 of which were related to a major leak at La Venta, Mexico in 1982 (Hirschberg et al., 1998). For the period 1969-1996, nearly 72% of the severe accidents in the gas chain occurred during transport by pipeline, with about 21% involving pipelines caused by mechanical failures and 24% by impact failures (Hirschberg et al., 1998, 2004).

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The regional distribution phase represents the most hazardous stage in all three energy sources, with at least 9,356 fatalities, 24,209 injured and 685,741 evacuees. The two worst disasters associated with the supply of natural gas, are those on December 2nd 1984 at Tbilisi in Georgia, where around 100 died, and April 8th 1970 at Osaka in Japan, where a similar number of fatalities occurred (Hirschberg et al., 1998). Casualties in the gas sector totalled around 2,223 dead, 5,210 injured and around 105,000 evacuated. Nearly 72% of the accidents in the natural gas sector occurred during the transport by pipeline

Three individual gas pipeline and supply incidents illustrate the significant damage that can occur and that more people have been killed in each incident than in all UGS incidents combined. The first incident relates to a large explosion along the El Paso natural gas pipeline, near the Pecos River at Carlsbad in southeastern New Mexico (Fig. 25; NTSB, 2003; Koper et al., 2003). Early in the morning of Saturday, August 19th 2000, 12 campers, including 5 children, were killed when the pipeline ruptured and exploded (registering 4 on the Richter Scale – Koper et al., 2003), creating a crater 26 m long, 14 m wide and 6 m deep (NTSB, 2003). The fire burned for an hour at temperatures of up to 1150°C, before being extinguished and rescue workers could eventually approach the site, when they found 12 people who had been camped near the bridge carrying the pipeline over the river, around 205 m (675 feet) from the explosion site (NTSB, 2003). All 12 eventually died of the injuries sustained and two nearby steel suspension bridges for gas pipelines crossing the river were extensively damaged during the incident, which remains one of the deadliest in American history (Koper et al., 2003).

The second incident relates to a gas explosion on the 21st October 1971 at a shopping centre in Clarkston, near Glasgow, Scotland in which 22 people died and 143 were injured, including

some on a passing bus (KAMEDO, 2000; Watson, 2003). The gas leak led to Scotland's biggest gas supply explosion despite a 6 day search during which gas workers failed to locate and fix a leak. The incident was exacerbated by the collapse of a car park into the shopping centre.

A third major gas pipeline explosion is of importance, providing significant information on casualties and damage zones (Hazards Intelligence, 2005; GDF, 2006). On July 30th 2004, a major natural gas pipeline, one metre in diameter and carrying "high calorific value gas" exploded in Ghislenghien, near Ath in Belgium (30 kms southwest of Brussels), killing 24 people and leaving over 120 injured, some critically. The pipeline is one of a parallel pair, carrying gas from the Belgian port of Zeebrugge to northern France and is operated by Fluxys, the Belgian gas pipeline operator. A second pipeline carrying "low calorific value gas" was not affected by the explosion (Hazards Intelligence, 2005).

Reports suggest that a gas leak was reported to fire fighters at about 08:30 local time and the explosions, which were heard several miles away, occurred at around 09:00 sending a wall of flame into the air. The explosions and fire destroyed 2 factories in the industrial park and melted or burned everything within a 400 m radius, leaving a large crater between the 2 factories (Fig. 26). Fire fighters attempting to establish a security perimeter around the site were among those killed. Of those killed, 22 were within 200 m of the release. Bodies and debris were thrown 100 m into surrounding fields. Investigations revealed that the pipeline had been damaged by a ground compaction machine during construction work, during which time the pipeline was being operated at reduced pressure. When the pressure was later restored to normal, the pipeline, scored by the teeth of the machine, failed (GDF, 2006).

Most recently in the UK, the major incident at the Buncefield storage depot in Hertfordshire illustrates the inherent dangers of fuel storage, in this case at an above ground tank facility (Powell, 2006a&b). On Sunday 11th December 2005 the oil depot, owned by Total UK Limited and Texaco, was rocked by a series of explosions, reported to be the largest of their kind in peacetime Europe (measuring 2.4 on the Richter Scale: BGS, 2005), which were followed by a major fire (Fig. 27). Although there were no fatalities, 43 people were injured and around 2000 people evacuated as the explosions and fire destroyed the site and caused serious damage to commercial and residential properties in the vicinity. The likely cause of the incident is thought to have been ignition of escaping petroleum vapour as a tank was overfilled (Powell, 2006a&b). It is widely acknowledged that, as at Flixborough in 1974 (HSE, 1975), had the incident happened during the week rather than in the early hours of a weekend, then the number of casualties would have been far higher, with numerous deaths likely.

The American Office of Pipeline Safety (refer http://ops.dot.gov/stats/stats.htm) provide statistics for reported incidents and casualties involving both hazardous liquids and gas supply in the period 1986-2006[part] (Table 15). These show there were 4,731 reported incidents involving gas transmission and distribution pipelines, which left 405 dead and 1,706 injured. The highest death and injury rates (344 and 1,461 respectively) are attributed to distribution lines, that is, low-pressure pipelines that take gas to cities, towns and houses. A further 3,679 incidents were associated with hazardous liquid pipelines and resulted in 44 dead and 272 injured.

In the UK for the same period (Table 16), there were 2,903 gas supply incidents (mainly domestic) that left 153 dead and 927 injured. A further 576 were killed and 3,346 injured as a result of carbon monoxide (CO) poisoning.

Casualty figures for significant petrochemical plant accidents between 1963 and 2002 reveal 3,674 dead, 303,340 injured and 7,200 evacuees (Table 18). Whilst the Union Carbide accident at Bhopal, India in December 1984 caused the majority of the deaths (3,500) and injuries (over 300,000), the remaining figures are again far greater than those associated with UFS. Casualty figures for 17 significant American railroad accidents associated with hydrocarbons in the period 1995-2004 reveal 9 dead, 5,441 injured and 10,452 evacuated (Table 19) – one more fatality, some 5380 more injured and 3752 more evacuated than have been reported in all UGS incidents. One major incident near San Carlos in Spain, which caused over 200 fatalities, resulted from an

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accident involving a lorry transporting propylene (Hirschberg et al., 1998). For the period 1951-2003, Persson & Lönnermark (2004), Clark et al (2001) and Ash (2006) detail incidents at above ground storage tank (or vessel) facilities that have killed at least 778, injured 426 and led to more than 7000 evacuees (Tables 14 & 20). One incident alone on 2 November, 1994 at Dronka in Egypt, resulted in 469 fatalities. Here a release of liquid (aviation) fuel from a depot of 8 storage tanks occurred during a rainstorm, thought to be the result of lightning. The blazing fuel flowed into the village where the majority of the deaths occurred (Clark et al., 2001).

10.2 DISCUSSION

As detailed in Chapter 9, 65 cases of problems or incidents at UFS facilities have been found as a result of UFS since UGS was first undertaken in 1915. Only 5 of the 65 incidents led to the 9 people reported killed during UFS storage. However, figures show that many industrial activities involve dangerous substances and have the potential to cause accidents giving rise to both serious injury to people and/or damage to property and the environment.

Oil and gas exploration, production and energy supply are no different. Incidents, involving casualty figures on a scale that dwarf UFS figures, can and will occur at all stages from production, during transport, storage and ultimately, use (Table 7). Any one of many incidents elsewhere in the energy supply chain has resulted in significantly more deaths than the combined total associated with UFS to date. Many of these incidents have occurred with infrastructure and facilities (major terminals, refineries and above ground storage facilities) that have been allowed to develop in close proximity to cities, major towns or centres of population. There is, therefore, a need to put casualty rates at UFS (and UGS) sites into perspective and gain better public understanding of the technology and levels of risk associated with UFS.

It is also worth re-iterating that natural pathways and mechanisms exist whereby hydrocarbon liquids and gases present in petroleum reservoirs do in fact reach the earth's surface (refer Chapter 3). Petroleum leakage to the surface is presently occurring in at least 126 of the 370 petroleum-bearing basins worldwide (Clarke & Cleverly, 1991). Oil and gas seeps occur in the North Sea and there are at least 173 occurrences of surface petroleum seepages and impregnations in Great Britain, many onshore (Selley, 1992). However, although hydrocarbons can and will slowly migrate by diffusion through cap rocks that is driven by buoyancy or chemical potential gradients, the presence of commercial accumulations of hydrocarbons proves the efficiency of the trapping structure over long periods (millions of years) of geological time. This is important in the context assessing the development of depleting oil and gas fields for gas storage purposes over extremely short periods of time that may be at most 100 years, with most estimated to be up to 50 years. The reader is referred to the accompanying report by Quintessa to assess the flux rates and volumes from various UK UGS scenarios to see the very small rates and volumes likely in all but the failure of a well (Watson et al., 2007).

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11 The Main Risk Analysis/Assessment Framework and Methods

The preceding chapters outline the various methods for UGS, previous problems encountered at UFS sites and the potential areas for UGS development in the UK. This chapter attempts to summarise the various risks identified or threats posed by UGS and provide a basis for the assessment of the risks during appraisal of future UGS/UFS applications in the UK. The nature of UGS, in that boreholes are required to inject gas at depth in both depleted oil/gasfields and salt caverns means that significant overlap in the various identified risks set out in Appendix 6 is found. These are simplified and summarised in this chapter.

As suggested previously, risk analysis and assessment requires identification of the main hazards. The following, therefore, summarises the main hazards and risks associated with UGS as found from the review of previous incidents and reported in the literature.

11.1 GENERAL CONDITIONS COMMON TO ALL UFS TYPES

There are certain categories of risk and hazard that are common to depleted oil/gasfield, aquifer or salt cavern storage facilities. They include:

- The well bore and immediate vicinity
- Leakage due to inadequate cap rock characterization
- The facility operating at pressures higher than the rock units have previously experienced. Except for depleted oil and gasfields, which in the UK would not normally be operated at pressures exceeding the original reservoir pressure (BS 1998a), one of the main risks and causes of leakage is due to the operation of underground aquifer and salt cavern gas storage facilities at pressures greater than the rock has previously experienced (overpressures or 'delta' pressures). This is related to maximising the working gas volume to attain higher delivery rates as well as achieving a greater return on investment
- Inaccurate inventories of stored or injected product – overfilling etc.
- Poor operational, maintenance or legislative procedures

11.1.1 The well bore and immediate vicinity

Experience from previous incidents at underground fuel storage facilities suggests that the biggest risks in both depleted oil/gasfield facilities and salt cavern storage arise from well problems (Fig. 28):

- Breaks/faults in the casing, joints or defective or poor quality cementing of casings, leading to
    - leakage through new or ageing injection well completions
    - leakage up abandoned wells
- Inadequate site characterization that would not detect the presence of unknown wells, with ageing completions that might penetrate to depths that would intesect either
    - the storage horizon,
    - a shallower level collector zone into which any gas escaping from storage might migrate to and collect in

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- During re-entry, repair or maintenance work on wells
- Inconsistent or inadequate monitoring of injection wells
- New oil or gas exploration wells drilled in poorly characterized/investigated areas and intersecting old mines, brine workings or existing facilities

11.2 ADDITIONAL SALT CAVERN RELEASE SCENARIOS

In addition to the potential problems with wells in both the depleted oil/gasfields and salt cavern storage facilities, a number of other potential problems are associated with the need to ensure cavern integrity and gas tightness.

The principal factors that contribute to the instability, breaching and collapse of solution mined salt caverns with the potential to release the stored product are (e.g. DeVries et al., 2002, 2005; Warren, 2006):

- Salt creep – section 4.2
- Uncontrolled leaching, both:
    - during cavern construction
    - during cavern operation (when operating in brine compensated mode)
- Presence of anomalous zones (higher solubility or porosity) in what has been assumed to be homogenous salt. This includes leaky interbeds or nonhomogeneous zones
- Salt body too shallow and affected by wet rockhead conditions (circulating groundwaters) – present in the UK and has been found to have caused problems and leakage of NGL's at the Conway NGL storage facility in Kansas and is described further in Appendix 5 (Ratigan et al., 2002)
- Inadvertent intrusion
- Release though the cavern seal
- Release of stored product through cracks in the cavern wall
- Partial cavern roof collapses, leading to thinning of the 'protective' cavern roof salt
- Collapse of internal ledges or benches formed by non salt interbeds
- Potential for gas to be (naturally) present in the salt beds
- Gas (or air) absorbing concentrated brine present in the sump and being highly corrosive and damaging to the steel well casings

11.2.1 Uncontrolled leaching

Uncontrolled leaching operations might lead to problems with cavern construction, producing unstable or poorly shaped and inefficient voids for gas storage. Problems might occur if, for example, more soluble evaporitic horizons (e.g. potash) are present within the bedded salt, unexpectedly thick non-halite interbeds are present or wet rockhead is developed (e.g. Myers et al., 1972). The presence of thick potash or wet rockhead could conceivably give rise to uncontrolled leaching leading to quicker than expected horizontal dissolution of the salt. This would be a similar situation to the intentional solution mining technique described by Myers et al. (1972). The brining operations have injection and production wells that are some distance apart with brining operations dependent upon the development of solution channel labrynths between the wells. In the context of salt caverns for gas storage, the development of solution channels could lead to problems of communication between adjacent caverns, or if two caverns are being brined simultaneously, connection and over enlargement.

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Uncontrolled leaching could also lead to unnoticed dissolution of the roof salt, which would be thinner than expected, or even absent. Potentially dangerous conditions could then arise, including collapse of the cavern roof and ultimately overlying strata, producing a surface subsidence crater as occurred during the development of a cavern facility at Bayou Choctaw, Louisiana and in Kansas (see Fig. 5c&d; also Coates et al., 1981; Neal & Magorian, 1997).

There are also recorded problems (refer section 9.3 and Appendix 5) of uncontrolled leaching having arisen during brine compensated gas storage operations, whereby caverns become enlarged giving rise to amongst other things, problems of quantifying the amount of product present (Brenham, Texas; NTSB (1993a&b, 2006); Thoms & Gehle (2000); Bérest & Brouard (2003)), thinning of salt walls between caverns (e.g. Mineola, East Texas; Warren, 2006) and the intersection of the sides of a salt dome. The latter led to the abandonment of the mined cavity before it was commissioned (Napoleanville, Louisiana; Neal & Magorian, 1997).

11.2.2 Inadvertent intrusion

The inadvertent intrusion scenario involves an exploratory well for oil or minerals that penetrates a hypothetical gas storage cavern. If the blowout-prevention system of the well failed, it could permit stored gas from the cavern to escape to the surface, leading to a release of gas and possible explosion/jet flame.

Of slightly different nature but related to this scenario are:

- Previous drilling in salt-prone sequences leading to developing caverns intersecting old wells
- New gas storage wells in areas of former mined salt as certain events in the USA where wells have intersected old mining cavities have illustrated (Warren, 2006 and section 4.8)
- Storage in abandoned salt mines with previously unknown or incorrectly located old wells where, for example, water intrusion can cause failure of the cavern seal and release of gas to surface (similar to the problem in Cheshire during active salt mining – section 4.8.2)

11.2.3 Release through the cavern seal

This scenario involves the failure of the seal that keeps gas within the cavern, permitting the release of stored gas to the well bore and thence to the surface, either directly or via pathways in shallower horizons. However, rather than the 'static' situation of sealed waste repositories, certain scenarios and settings might present more risk during continued operation of the storage cavern during injection and withdrawal cycles.

Well casings are generally steel and with time these tend to deteriorate (corrode) due of the presence of brine, which ultimately leads to failure of the well casing. Initially this will be close to the top of the cavern, but in the long term, the well casing is likely to fail at shallower depths. If left fully pressured for long periods, the pressure in the cavern could, due to the combined effects of the addition of heat from the surrounding salt and salt creep, potentially increase. If the cavern pressure were to reach a high enough value then the cavern seal might fail if the plug cracks and the salt around the seal dissolves, or by some other means. Gas could then move up the well bore towards the ground surface as the pressure in the cavern is reduced to the hydrostatic value.

It should be noted that at the Huntorf salt cavern CAES facility, even fiberglass reinforced plastic (FRP) casing, which replaced the original 13⅜ inch steel production casing in the 1980s, has experienced corrosion (Bary et al., 2002). Corrosion avoidance measures there have included injection of dry air between steel and the FRP casings. It was found that brine in the cavern sump area became highly concentrated and was readily absorbed by the compressed air. The air

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became highly corrosive and when released, it quickly caused dmage to the steel casings, which were replaced at least once before the RFP casing was installed.

While ascending the borehole, gas from the cavern could also move laterally into adjoining formations if the well casing has failed. Well casing, generally being made of ordinary steel, presents a high probability that it would suffer damage when exposed to groundwater containing brine over time. Two possible cases might be considered under this scenario:

(1) the casing fails at the depth of the cavern (at or near the cavern roof) and gas is released to a deep aquifer

(2) the casing fails at a shallow depth and releases gas to a near-surface aquifer.

In terms of the storage of gas, the potential for this leakage route to occur could be increased as a result of the cyclic pressuring and depressuring of the cavern. If minimum pressures are not strictly monitored, then it could lead to weakening of the salt in the cavern roof around the well. Cracks or fractures could develop in the salt and degradation of the seal formed between the salt and well could also occur, through which gas might escape and enter the well string and thence reach the surface.

11.2.4 Release of stored product through cracks in the cavern wall

Cracks in the salt cavern walls that might develop if minimum pressures in the cavern are not maintained, with the result that the salt dilates (microfractures and spalls), releasing gas into the surrounding salt cavern walls and roof. Such a damaged zone could then intersect non salt interbeds and permit transport of the gas away from the cavern. The damage might also develop during pressurization of the cavern or because of the combined effects of thermal heating and salt creep. The volume of gas released would be a function of the pressure in the cavern, the volume of the cracks, and the crack pressure. Depending on the pressure in the cracks, they could self-heal after the release as a result of additional salt creep, but repressurization of the cavern could also lead to reopening of the cracks.

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11.2.5 Release of gas through leaky interbeds or nonhomogeneous zones

In this scenario, the cavern is assumed to intersect a leaky interbed or heterogeneity that allows communication with the outside environment. As the cavern pressure rises because of injection and/or thermal effects/salt creep, gas could be expelled into the interbed where it might be transported laterally under existing pressure or chemical gradients.

11.2.6 Partial cavern roof fall

Loss of cavern integrity through a partial roof fall coupled with failure of the cavern seal could release gas. If the collapse is not noticed, then the release might be in a series of short pulses separated by periods of low to no discharge when the pressure in the cavern is increasing because of injection or (less likely) salt creep. A partial roof fall coupled with a release through leaky interbeds or nonhomogeneous zones of higher permeability material would manifest itself as a long slow release.

Cyclical pressuring and depressuring of the gas in the cavern could, if minimum pressures are not strictly monitored, lead to fracturing and collapse of the cavern roof and walls. Collapse of the roof would pose an immediate threat not only to the cavern seal at the entry of the well bore string, but also the well string within the cavern.

11.2.7 Collapse of internal ledges or benches formed by non salt interbeds

In terms of UK gas storage this scenario potentially represents a threat in onshore areas where bedded salt is being considered for cavern development. Many caverns in the USA are

constructed in massive salt domes formed during salt movement (halokinesis). This gives rise to salt that is both very thick and generally very uniform in nature. Caverns, however, are also constructed in thick-bedded salt (halite) sequences, which contain interbedded non-salt layers of varying thickness. In the UK context only offshore, in for example, the Southern North Sea and East Irish Sea areas, halokinetic features are developed. Onshore in the UK the halite is of the bedded type, although in the Portland area, some minor halokinesis may have occurred, where the Triassic halites appear to thicken slightly into the core of the Weymouth Anticline (Appendix 3, Fig. 57; see Chadwick & Evans, 2005). Solution mining of such bedded salt deposits requires that careful characterization of the salt body has been undertaken to ensure that the existence, nature and extent of the non salt interbeds are known. This should help ensure that the brining process does not leave benches or ledges of thicker units protruding into the cavern and through which the well strings have to pass. Clearly, collapse of such benches into the cavern could damage the well string and possibly lead to a major incident if the cavern had been commissioned before the collapse occurred.

It is possible to manage such benches or ledges by a controlled collapse, but the resulting debris will fall into the sump at the base of the cavern, reducing both its effective volume and impacting on the storage volume.

11.2.8 Potential for gas to be (naturally) present in the salt beds

Gas has been encountered in salt beds or formations both in the UK and USA. It has led to blowouts in mines and has led, in instances in the USA, to problems of verifying product inventory where the volume of gas held in storage has increased. Gas generated within the salt body has moved through the salt into the storage cavern along anomalous zones (AZ's; Neal & Magorian, 1997). Gas is known in the Boulby Potash Mine in NE England (section 4.3.1) and may be of relevance to salt cavern development in Permian salts.

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11.3 SPECIFIC TO DEPLETED OIL/GASFIELDS - DRIVE MECHANISM

Of potential importance and specific to oil/gasfield storage scenarios is the drive mechanism during production. Depletion drive in gasfields would leave the pore spaces largely filled with gas, whereas water drive would result in water invasion into the reservoir. Storage in the latter scenario would require greater injection pressures in order to drive the water out of the pore spaces. This could increase the risk of overpressuring the area surrounding the borehole and cause fracturing of the reservoir rock. Similarly, injection and storage in depleted oilfields, with oil remaining in the pore spaces (+/- water invasion), might require greater pressures than injection and storage in gasfields.

11.4 RISK ASSESSMENT PARAMETERS FOR CONSIDERATION IN RISK ANALYSIS/ASSESSMENT OF UK SCENARIOS

In terms of the UK and as described above, 2 main types of storage have immediate potential:

- Depleted oil and gasfields
- Salt caverns in bedded salt

To assist in the assessment by Quintessa of the risk of storage, release and flux rates of product to the surface in either scenario, a list of parameters relevant to a proposed site was prepared and includes the general stratigraphy, any faulting present and the number of deep boreholes of differing depth within 1, 3 and 11 km of the proposed site area etc. These summaries are provided for both storage scenarios relevant to various areas of the UK. The details may be found in Appendix 7.

11.4.1 Risk assessment and modelling of UK scenarios

Based upon the results presented in this report and their experience in underground CO2 storage, Quintessa compared the main leakage scenarios with a series of features, events and processes (FEPs) developed for CO_2 storage studies and developed a series of FEPs relevant to UGS and in the UK context (Watson et al., 2007). Then Quintessa undertook the risk assessment and calculations for gas releases from potential UK UGS facility scenarios.

The FEP analysis provided a systematic framework for identifying issues that are relevant to the overall safety of the gas storage site, but also ruled out less important issues at an early stage. Based on the outcome from the FEP analysis and the scenario selection, the main features and events were identified (Watson et al., 2007). From these, Quintessa then ran models for the 2 basic storage scenarios currently being considered in the UK, and within each of these categories two end member states were considered, namely:

- Salt caverns
    - Low permeability (K) geosphere – storage horizon mainly overlain by low permeability mudstones and other salt beds
    - Mixed permeability (K) geosphere – storage horizon overlain by mudstones and Jurassic and Cretaceous rocks
- Depleted oil and/or gasfields
    - Low permeability (K) geosphere – storage horizon mainly overlain by low permeability mudstones plus or minus salt beds
    - Mixed permeability (K) geosphere – storage horizon overlain by a relatively thin caprock of mudstones succeeded by mixed permeabilty sequence of Jurassic and Cretaceous mudstones, sandstones, limestones and chalk.

For the depleted oil and gas system the Quintessa report deals only with a mixed-K geosphere model. A low-K geosphere is not dealt with explicitly because the range of fluxes calculated for the mixed-K geosphere would bracket those for the low-K geosphere. This is because a wide-range of low-K formation thicknesses are considered in the calculations for the mixed-K geosphere. Instead, the main difference between the two geospheres is that potentially there will be different pathways for gas migration, details of which are considered and discussed in more detail in the Quintessa report (Watson et al., 2007).

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11.4.2 Mitigation

The area of mitigation is a wide-ranging subject that cannot be adequately covered here. The section therefore highlights a few major points and areas that might be considered as an initial starting point for any studies or design.

In the event of an incident and a leak (or worse) occurring, then systems should be in place to bring the situation back under control as soon and as safely as possible. Methods for mitigating and remediating risks caused by leakage of gas from the primary storage reservoir should be developed and might include (in no particular order):

- Lowering storage pressures within the storage reservoir or cavern, to
    - Prevent leakage or damage to the cap rock
    - Improve immediate safety and allow considered approach for ensuing stages
    - Permit the design of remote secondary wells, or (with more risk involved) the drilling of new access wells to enable safe access to, and withdrawal of the stored product remaining

- In the event that leakage has occurred, gas that has accumulated in shallow traps can be pumped out to prevent further migration and surface releases (as seen at a number of the Illinois aquifer storage facilities)
- Monitoring of injection/production/abandoned wells to detect damage or leakage – perhaps involving a regular sonar logging run
- Repair of leaking injection/production/abandoned wells
- For salt caverns, performing regular sonar scans to accurately map the cavern walls and monitor closure – tools are now developed to run in the cavern even when the cavern contains gas
- Extreme case scenario – facility abandoned by either
    - Withdrawal of the remaining stored gas
    - Being left to burn out (an extreme case, but has occurred e.g. at Moss Bluff, Texas)
    - All injection/withdrawal wells plugged, following strict guidelines/regulations
- In the case of salt cavern storage facilities and as discussed by Hopper (2004), the installation, during cavern construction, of a remote second well system that would allow safe draw down of the stored product in the event of an incident. This would carry its own risks, however, in that it represents an additional intrusion of the reservoir or salt cavity and potential pathway back to the surface
- On abandonment, closure and monitoring of salt cavern stability and internal pressure to prevent overpressuring and possible failure of he walls or roof rock and the wellhead/valves
- On abandonment of depleted fields (or aquifers, if ever developed), withdrawal of injected stored gas to below cushion gas levels, as undertaken in some decommissioned facilities (e.g Ketzin)

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12 Summary and Conclusions

From this report and many others cited herein, it is clear that a number of factors are critical to the successful safe design and construction of UGS storage facilities, including:

- The site provides strata deep enough for safe and economically viable storage of gas under high pressures
- Development of UGS requires that the site is adequately characterized, geologically
    - For pore storage this requires adequate knowledge of the storage area, based upon
        - Accurate depth maps of the reservoir horizon
        - Accurate thickness (isopach) maps of the reservoir horizon
        - Superficial deposits mapped
            - Nature of the deposits – presence of any potential 'collector zones' (higher porosity layers)
            - Their distribution across the proposed area
            - Their thickness or the depth to rockhead
        - Knowledge of any faulting across the structure/storage area
        - Producing a sedimentary model for both the reservoir and caprock lithologies to provide information on
            - Porosity and permeability
                - distribution across the area
                - distribution vertically through the reservoir
            - Thickness and extent of storage reservoir
            - Interconnection or isolation of sandbodies
        - Caprock integrity
            - Thickness and distribution
            - Geological structure – including presence of faults in reservoir or caprock
            - Lithology
            - Physical properties (porosity, permeability, pore entry pressures etc.)
            - Mechanical properties (e.g. strength)
    - Salt caverns require similar geological characterisation and adequate knowledge of the porposed site area
        - The thickness, depth and extent of the salt beds
        - The thickness, depth and extent of the caprock sequence and its suitability
            - Lithological heterogeneity
            - Presence or absence of fractures

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        - Open or infilled
        - What mineral – studies of fractures may show several stages of development and differing types of infilling material
      - Rock mechanical properties
    - Superficial deposits are mapped
      - Nature of the deposits – presence of any potential 'collector zones' (higher porosity layers)
      - Their distribution across the proposed area
      - Their relationship to any development of wet rockhead
      - Their thickness or the depth to rockhead
    - The sedimentary environment that will permit understanding of
      - The presence and nature/distribution/thickness of non salt interbeds
      - The presence and nature of more soluble evaporite beds
      - Lateral changes in sedimentary facies
    - The geological structure, including the likely presence of faulting in overlying sequences and whether, for example, large faults define the margins of the saltfield
- That the facility is designed and operated with sufficient safety measures to ensure the storage reservoir or salt cavern cannot be inadvertently or otherwise overpressured
- Proper design, construction, monitoring and maintenance of injection/withdrawal wells
- Abandoned wells in and around the proposed storage area must be accurately located and previous completions checked for integrity and gas tightness.

Clearly all the above can only be obtained through detailed site characterisation and geological investigations. In depleting oil and gasfields, much of this work will have been undertaken during the exploration and production phases when such detailed knowledge of the reservoir and structure is required to maximise production. For aquifers, most of the investigations required to discover and develop oil/gasfields has to be undertaken. For this reason aquifer storage sites are generally more costly to develop.

Developing salt cavern storage facilities requires detailed geological investigations in order to prove the depth, thickness, extent and purity of the salt beds in which it is proposed to develop the caverns. Boreholes have to be drilled to provide samples of the halite for in situ and laboratory tests to gain information of the strength and mechanical properties. However, there is a 'Catch 22' situation. Ideal cavern storage sites are safer when few boreholes penetrate the cap rock and salt succession. This is perhaps also true for depleted fields, although possibly less so in that releases will be somewhat slower due to the physical constraints of the gas being 'produced' from pore spaces. Therefore, careful design and planning of boreholes is required to generate the least number of borehole penetrations that could form a route back to the surface for any gas that might escape from the salt cavern. Ideally, site characterisation would involve non-invasive investigative techniques such as seismic reflection data (perhaps a 3D cube) to aid building up a 3D model of the subsurface structure and distribution of the salt beds. Seismic data (perhaps acquired with high frequency sources), tied to geophysically logged boreholes, would offer the greatest potential to image any faulting that might affect the proposed storage site.

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A review of casualty figures from other areas of the energy supply chain, including above ground storage vessels, allows those figures associated with UGS/UFS to be compared with other storage environments and energy supply sectors in order to assess the conclusions of Bérest et al. (2001) and Bérest & Brouard (2003). These authors state that "salt caverns provide one of the safest answers to the problem of storing large amounts of hydrocarbons". Pore storage facilities are associated with even lower incident rates. Even in urban areas such as Los Angeles Chillingar & Endres (2005) concluded "...Underground gas storage, oil and gas production can be conducted safely if proper procedures are followed. After recognition of the existing problem, proper safe operating procedures can be easily developed"...

Whilst it is acknowleged that the figures reported here probably represent a minimum (i.e not all incidents have been found, or were reported), the figures collated during this work indicate that UGS has extremely low incident and casualty numbers when compared to these other areas. The results from 2 smaller studies on the safety of UGS undertaken for both the natural gas storage industry and researchers in the field of the underground storage of CO_2, support the results of this study. Casualty rates several orders of magnitude greater are reported from other sections of the energy supply chain and which individually, have often resulted in more deaths than those of not just UGS, but all combined UFS described here. This includes fatalities arising from the supply of domestic gas in the UK.

Contrary to public belief, UGS is regarded by other sectors of industry and research as having an excellent health, safety and environmental record (Lippman & Benson, 2003; Imbus & Christopher, 2005). Even in the infamous Hutchinson incident, it would appear that it was not failure of the cavern, but human error and poor operational and safety controls that led to the leak, resulting in the explosions, fires and 2 fatalities.



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Appendix 1 Gas migration rates – hydrocarbon-bearing basins

Source	Area	Nature	Source depth	Flux	Flow/seepage rates rates	Effective Diffusion rate	Migration velocities calculated
Cheyne & Dando (1996)	N Sea 1 (Block 15/5	Biogenic gas (Tertiary reds)		440 L/m²/yr	0.14-0.6 L/hr		
Hovland & Sommerville (1985)	N Sea 2 (Ekofisk area -- over 100000m²			890 L/m²/yr	1860 L/hr		
Dando et.al. (1994)	N Sea 3 (Kattegat coast, Denmark -- over area of 1700 m²	Biogenic gas (Brunian)	> 1000 m	520 L/m²/yr	0.15-21 L/hr		
Hovland & Sommerville (1983)	Norwegian N Sea	Deep seated thermogenic source			24 m³/day		
Krooss & Leythaeuser (1996)		Russian rock salt (Aninov et al., 1958)		88.5 m³/km²/yr		2.8×10^{-10} m²/sec	
		US Shales (Smith et al., 1971)	1737 m (overburden)	1.9 m³/km²/yr		6.9×10^{-10} m²/sec	
			150 (seal) 1590 (overburden)	1 m³/km²/yr		3.4×10^{-11} m²/sec 6.9×10^{-10} m²/sec	
		shale (Neuzilov & Ushatinskij, 1972)		0.16 m³/km²/yr		5×10^{-12} m²/sec	
Leythaeuser et al., 1982 Krooss et al., 1992a&b) Nelson & Simmons (1992)	Hutlingen gas field (Baltic)		390 m	3.7 m³/km²/yr		21.0×10^{-10} m²/sec	
Mosnil et.al., (1993)			Cheyenne, 550m	10 m³/km²/yr			
Neuzilov & Ushatinskij (1972)		Total diffuse gas loss - 17×10^6 m³ over 25 my	shale	680 m³/yr			
Kettel (1996)	Mountrelund Basin	B2/4		2.91 $\times 10^6$ m³/km²/x200000 yrs			
		B2/5		2.91 $\times 10^6$ m³/km²/x200000 yrs			
		B2/6		2.57 $\times 10^6$ m³/km²/x200000 yrs			
		B2/7		5.60 $\times 10^6$ m³/km²/x200000 yrs			
		B2/8		1.52 $\times 10^6$ m³/km²/x200000 yrs			
	Lower Silesian Basin	1		9.30 $\times 10^6$ m³/km²/x10 my			
		9		3.75 $\times 10^6$ m³/km²/x10 my			
		10		1.19 $\times 10^7$ m³/km²/x10 my			
		13		1.12 $\times 10^7$ m³/km²/x10 my			
		18		5.80 $\times 10^6$ m³/km²/x10 my			
		19		1.30 $\times 10^6$ m³/km²/x10 my			
		31		6.51 $\times 10^7$ m³/km²/x10 my			
		32		6.51 $\times 10^7$ m³/km²/x10 my			
		33		5.40 $\times 10^7$			

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				$m^3/km^2/a$ 10 my			
		54		4.54 $x10^7$ $m^3/km^2/a$ 10 my			
	Upper Rhine Graben	5		1.15 $x10^7$ $m^3/km^2/a$ 10000 yrs			
		8		1.00 $x10^7$ $m^3/km^2/a$ 10000 yrs			
		9		5.00 $x10^7$ $m^3/km^2/a$ 10000 yrs			
		10		8.00 $x10^7$ $m^3/km^2/a$ 10000 yrs			
		11		1.15 $x10^7$ $m^3/km^2/a$ 10000 yrs			
		61		1.00 $x10^7$ $m^3/km^2/a$ 10000 yrs			
		62		2.00 $x10^7$ $m^3/km^2/a$ 10000 yrs			
		64		1.60 $x10^7$ $m^3/km^2/a$ 10000 yrs			
		65		1.00 $x10^7$ $m^3/km^2/a$ 10000 yrs			
Arp (1992)	Patrick Draw Oilfield, Wyoming		1576 m (5200 ft)				76-305 m/yr (250-1000 ft/yr)
Andriani et al. (1982)	Lacy Storage Field, Wyoming						305 m/yr (1000 ft/yr)

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(Cont.)

Appendix 2 Problems and subsidence experienced at saltmines and brine caverns – i.e. not associated with gas storage

Section 4.8 briefly introduced problems that had been encountered at salt and brinefields that were not related to wet rockhead or linked to gas storage operations, but that could have a bearing on how saltfields may be developed for cavern gas storage. The nature of problems encountered at salt mines and brinefields where catastrophic ground failure arose either from poor working practices, or problems that occurred of old oil and brine wells in areas of halite and old mine workings are briefly outlined (see Warren, 2006). The examples are relevant to proposals for UK gas storage in salt caverns. They illustrate the problems and dangers that can occur in areas when brining operations are poorly controlled, or site characterization and defining the positions of old abandoned oil or brine wells and liaison with relevant authorities has been inadequate.

Problems in saltmines and brine caverns, including old brinewells

Ocnele Mari Brinefield, Romania

An incident at a salt mine in Romania producing salt by solution mining, though not directly linked to gas storage caverns is worthy of note. It represents a potential problem that could arise if uncontrolled or poorly managed solution mining of a cavern without due regard to, or control over, the shape, dimensions or long term geological stability of the resulting cavity. As such, consideration is briefly given to the problem at the Romanian Ocnele Mari field 2 (http://www.saltinfo.com/Romania.htm).

The brine field has been worked over the period 1961 to 1993, with old caverns left brine-filled. Over-mining caused the development of a huge cavern, reaching around 250 m in diameter, with a volume of about 3.7 Mcm, and a corresponding surface area of about 10ha (http://www.saltinfo.com/Romania.htm). This was created by the inadvertent dissolution of pillars separating adjoining caverns (http://www.solutionmining.org/smri.cfm?a=cms,c,33). Although mining operations at the cavern location ceased in 1993, some caverns have subsequently collapsed, leading to subsidence of the ground above. There are very real fears of total collapse of the remaining caverns, destroying 22 homes on top of the cavern and releasing up to one million cubic meters of brine. This would flood of the Sarat River valley for many kilometres and put hundreds, perhaps thousands, of residents in the river valley at risk.

In 1991 SOCON (a German company specialising in cavern sonar imaging) and Romanian hydrogeologists independently undertook investigations and evaluations of the situation in Ocnele Mari. Their aims were to determine the risk factors and how to stabilise the field and thus prevent the collapse of the remaining caverns. Two opposing opinions emerged on the action to be taken to stabilise the cavern field. SMRI reported in 2001 that the problem could still be stabilised if immediate remedial action based on backfilling were taken. The situation progressed, with a partial collapse of the field occurring in the summer of 2001. In November 2001, the total collapse of the remaining caverns was regarded as 'imminent'.

The problems at Ocnele Mari would not have arisen if normal 'best practice' mining engineering principles had been employed in its development (http://www.saltinfo.com/Romania.htm).

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Old Belvedere Spinello, Italy

The Old Belvedere Spinello brinefield in southern Italy was originally operated via brine wells interconnected by hydraulic fractures. The area exhibits subsidence effects ranging from sinkholes to bowl subsidence and landslides. A major collapse occurred, caused by the salt solution mining process, which went unnoticed. Solution mining of the salt beds had apparently migrated undetected away from the brinewells some considerable distance updip within the salt formation, to where a large cavern had been dissolved out, previously. This cavity lay below the toe of a hill and when a sinkhole developed, the hillside collapsed and caused major flooding. Solution mining is now undertaken in a new area of the brinefield using a number of sonar monitored salt caverns accessed by single wells (Warren, 2006).

Brinefield and mine collapse, Krakow, Poland

A former salt mining region, centred on Krakow in southern Poland has mined Miocene age salts since the 13th century. Two main problem sites exist, at Barycz and Lezkowice (Warren, 2006). The Barycz mine covers an area of 1 km^2, being 2 km wide at its maximum. The salt formation is flat lying around 30 m thick and 230-280 m below ground level. Solution mining was first carried out in 1923. At Lezkowice, the salt dips steeply and occurs as little as 40 m below the surface. Salt was solution mined to a depth of more than 450 m. Both sites are covered by 15-20 m of unconsolidated Quaternary sands, gravels and peat.

At its height, the Barycz brinefield had more than 900 solution wells about 50 m apart. Total production was equivalent to a 3 m thick unit across the whole site. Significant ground subsidence occurred from the outset, with 10-30 cm noted in the period 1926-1934 and 33 sinkholes up to 27 m across and 27 m deep forming between 1923 and 1993. The land surface is now pock marked by stagnant brine filled subsidence cones and sinkholes often centred on abandoned wells (Warren, 2006).

Depletion of the Barycz brinefield meant operations were moved to the Lezkowice site in 1968, where exploitation was carried out using brinewells sited 35 m apart. Operations were meant to be controlled and regulated to avoid the problems encountered at the Barycz brinefield. However, this never happened and operations went unchecked for 20 years until the brinefield was shut down in 1988. By then, numerous cavities had joined and subsidence problems were being encountered, with two areas where it was more than 80 cm and a maximum of 1.2 m. In an attempt to reduce its impact, local industrial waste material was injected into some of the cavities.

Gellenoncourt saltworks, France

On March 4th 1998, a sinkhole measuring 50 m across and 40 m deep was induced above two brine caverns in the Gellenoncourt saltfield near Lorraine in France, opened in 1967. Collapse was triggered to prevent future uncontrolled ground collapse (Warren, 2006). Two brine caverns, each designed with a substantial salt roof to protect the overlying Triassic marls, formed part of a field of caverns. In 1971 the two caverns unexpectedly joined and although brine extraction was stopped, cross-flowing brines flowing into another producing well continued to leach the two caverns. By 1982, the salt roofs to the two caverns had been dissolved away. Between 1982 and 1992 no further upward growth of the cavern occurred. However, a 25 m thick section of the marls fell in, stopping only because of an interbedded dolomite bed that prevented further collapse of the strata and propagation of the cavity to surface.

Retsof Mine, New York State, USA

The Retsof mine covered an area of 24 km^2 and was the largest working saltmine in the USA. It had been in operation since 1885 (Warren, 2006). The problems at the Retsof mine began in March 1994 with a magnitude 3.6 earthquake caused by the (catastrophic) collapse of a small pillar and panel section of the mine. This was accompanied by collapse at the surface of an area 180 m by 180 m and 10 m deep. A month later an adjacent mine room collapsed, forming a

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second crater. Collapses were accompanied by influx of brine, flooding of the entire mine within weeks and causing the loss of the entire mine operation. Associated aquifer drawdown led to inadequate water supply for months following the collapse, with some wells drying up altogether.

Brinefield subsidence, Windsor, Ontario

In 1954, subsidence, followed by collapse, destroyed part of the infrastructure of an active salt works near Windsor, Ontario (Warren, 2006). The first well was drilled in 1902 with intensive exploitation commencing in 1922, with 25 wells drilled between 1922 and 1953. Prior to the collapse, an area around 300 m across and 40 cm deep had subsided in the preceding 5 years. The collapse in February 1954 occurred over a 9 hour period and destroyed most of the surface plant.

Sinkholes at Cargill, Kansas

A number of sinkholes appeared in the 1950s and 1970s around brinewells and salt caverns near Hutchinson, Kansas (see Fig. 5c&d and http://www.kgs.ku.edu/Hydro/Hutch/Subsidence/index.html). The area has had numerous wells extracting brine from bedded Permian salts around 105 m thick, some 130 m below surface (Walters, 1978; Warren, 2006). Several collapses have been noteworthy, including the Cargill collapse sink in 1974, which formed above a breached salt cavern. Within four hours of starting, it was 60 m across. After three days, it had formed a circular depression 90 m across and nearly 15 m deep. The sinkhole developed in an area that was part of an active brinefield at the time and included both operating and abandoned wells. A number of railway lines had been built on the brinefield and the sinkhole developed beneath the junction of three lines, leaving them suspended across the crater (Fig. 5c&d). A further large sinkhole is developed in the area to the immediately to the north of the salt (refer Fig. 5d). Within the sinkhole area, was an old well drilled in 1908, which was plugged and abandoned in 1929. Earlier uncontrolled brine extraction in the region since as early as 1888 contributed to the collapse and new regulations now require all caverns to retain a 12 m thick salt roof to protect the overburden.

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Sinkholes in the Detroit River

In 1971, several sinkholes developed in and around Hennepin Point near the Detroit River, some 10 km downstream from the Windsor collapse (Warren, 2006). Production of brinefield salt began in 1943 and the sinkholes resulted from 30 years of solution mining at depths of more than 320 m, using poorly completed or protected wells. Salt cavities quickly coalesced to form larger cavities. The largest cavity was created from two caverns and ground subsidence was noted in 1960. Subsidence was constant until 1967 after which it accelerated until the first collapse crater formed in February 1971. Its subsidence history closely mirrors that of Windsor, with a second larger crater formed in May 1971.

Sinkhole at Bayou Choctaw Dome, Louisiana, USA

A brine well in the Bayou Choctaw salt dome collapsed during brine production in 1954 as a result of loss of the salt roof above a growing cavern. A sinkhole formed at the site, into which a rig collapsed. Eventually a lake 210 m in diameter developed.

Grand Saline sinkhole, Texas

A sinkhole appeared at surface within the city of Grand Saline, Texas in 1976. It developed at the site of a former brine well that produced brine between 1924-1949 from the Grand Saline salt dome, the top of which was only 60 m below ground level. A sinkhole 15 m in diameter developed, causing the collapse of a sewer.

Winsford Mine, Cheshire

Salt mining at the Winsford Mine commenced in 1844, although the mine was closed between 1892 and 1928 (BGS, 2006). Since 1928 it has been the major source of rock salt in the UK.

Extraction is by room and pillar mining and is currently from the Bottom Bed of the Northwich Halite Formation at a depth of about 140 m. The salt is extracted from galleries 8 m high and 20 m wide. Pillars are 20 m x 20 m, which gives an extraction rate of 75%. Formerly, drill and blast methods were used for salt extraction. However, since 2002 a continuous mining machine has been used to extract the top 'lift' of 4.5 m, with either bench blasting or a continuous machine being used for the bottom 3.5 m. The mine is dry and stable and room and pillar mining creates little or no surface subsidence.

However, the intersection of a borehole in 1968 caused serious flooding of the mine and as a result, protection barriers of 75 m are now left around boreholes (BGS, 2006a).

Examples of problems associated with old (non brine) wells in salt bearing successions

Again, the list of examples in this Appendix is not exhaustive, merely illustrative.

Wink Sink, Winkler County, west Texas, USA

The Wink Sink oil well is an example of problems with a well arising from drilling through thick salt beds. The incident at Wink Sink, Winkler County, west Texas, centred on an abandoned oil well within the giant Hendrick Oilfield (Warren, 2006). The oilwell had been drilled and completed to industry standards of the time in the late 1920s and had produced oil from 1928 to 1951. It was finally plugged in 1964.

The incident involved the development of a sink or subsidence crater, which first formed in June 1980, centred on the abandoned well. Within 24 hours the sink was around 110 m wide and within 3 days was 34 m deep. Investigations found that the collapse was the result of an underlying solution cavity that had developed in Permian halite beds 400 m below. It had migrated upwards by successive roof failures until it eventually breached the land surface.

The process of dissolution, cavity growth and resultant chimney collapse were accelerated by drilling and inappropriate well management practices in the immediate area of the well in the early part of the 20th Century. Several factors and events were clear:

- Use of fresh water drilling fluid at the time
- Nitro-glycerine had been used to straighten the hole
- Casing too short to isolate aquifers, permitting fresh water into the borehole surrounds
- Poor cementing of the well failing to seal adequately the salt beds behind the casing, thereby opening a vertical pathway for movement of undersaturated brine up or down the borehole surrounds
- Inappropriate cement for basal section of the borehole in saline conditions.
- Corrosion of the casing and cement by salt water
- Possible fracturing of original cement during later workover, re-entry and plugging operations.
- Removal of some critical casing during the final plugging and abandonment of the well in 1964, which would have permitted movement of water up or down the borehole surrounds.
- The absence of cement plugs or linings to the well below a certain depth during operation would also have allowed movement of water up or down the borehole
- The pumping of large amounts of brine water between 1928 and 1951, would have caused significant cross flow of undersaturated water and further assisted corrosion of the casing and dissolution of the salt.

D2-253 (Cont.)

Drilling, completion and plugging procedures therefore, combined to create a conduit that enabled fresh water to circulate more effectively in the vicinity of the borehole and thereby dissolve salt. Once dissolution and cavity formation was sufficient, roof collapse into the cavity occurred. The Wink Sink collapse thus illustrates the importance of (Warren, 2006):

- Appropriate well design specifications
- Reliable maintenance during well life
- Need for adequate plugging and abandonment procedures specifically designed for wells passing through salt or salt prone intervals.

Panning Sink, Barton County, Kansas, USA

The Panning Sink formed in April 1959 as a result of subsidence and collapse around a saltwater disposal well, abandoned the previous January because of uncontrolled wellhead tilting. The suspect well (Panning 11a) was originally drilled as an oil well in 1938 and penetrated the Permian Hutchinson salt about 200 m below ground. It was drilled using freshwater which caused the dissolution of the salts, with the result that the cavity thus formed was not cemented in behind the casing. The borehole was converted to a saltwater disposal well between 1946 and 1958, further dissolving the salt behind the casing and leading to roof falls and upward migration of the collapse chimney. Eventually, the cavern reached ground level, forming a 90-metre wide water-filled sinkhole in about 12 hours, which continued to gradually widen over the next few days.

Gorham oilfield, Russell County, Kansas, USA

The largely depleted giant Gorham Oilfield, produced from around 1,397 oil wells, is the site of slow ongoing subsidence above salt dissolution zones in the Wellington Salt, which is equivalent to the Permian Hutchinson Salt, described elsewhere in this report. A number of wells drilled in the period 1936-1937 that pass through the salt are now plugged and abandoned. However, corroded casing has been left in these holes above, within and below the salt, permitting unsaturated water to flow up and down some of the boreholes, dissolving large volumes of salt. Subsidence was also aided by disposal of waste oilfield brines that were reinjected when under saturated with respect to halite.

Lake Peigneur, Louisiana, USA

Lake Peigneur is a natural water-filled depression approximately 2.4 km in diameter located on top of the Jefferson Island salt dome in the low-lying Gulf Coast area of Louisiana. The Jefferson Island salt mine works are nearby.

On November 20th 1980, a sinkhole started to develop during drilling of an oilwell from a pontoon in the lake. The oilwell intersected an unused section of the salt mine around 350 m below lake level. Within 12 hours the lake had drained, leaving a collapse sinkhole 0.91 km^2 in area. The surface entry hole in the floor of the lake quickly grew to a half-mile wide crater. Fifty personnel were working underground in various areas of the mine at the time and were safely brought to the surface. In the days following, the surrounding sediments collapsed into the crater, sealing the hole. The waters of the Gulf of Mexico refilled the depression and restored the lake.

This episode illustrates how quickly incidents can arise and how human error (in the form of a lack of due diligence, forward planning and communication between various private and government authorities) once again contributed to a major accident (Warren, 2006). It also demonstrates how quickly potential leakage could occur following a breach in a cavern roof in any shallow storage facility filled with low density and mobile fluids.

Haoud Berkaoui Oilfield, Algeria

In October 1986 a crater around 200 m in diameter and 75 m deep appeared in the Haoud Berkaoui Oilfield in Algeria. It continued to expand and reached around 230 m by 600 m across,

D2-253 (Cont.)

at a growth rate of about 1 m per year. The collapse is centred on two oil wells drilled in the 1970s, one of which was abandoned due to well stability problems, with no casing near the bottom of the well and just below an evaporite sequence. The absence of casing, properly cemented inplace, allowed water to percolate into surrounding salts. A second well, drilled in 1979, was located 80 m away and completed successfully. However, in March 1981 the lining of the second well fractured due to cavity formation in the salt, with the creation of the large crater, as a result.

As with the Wink Sink, the loss of the wells again shows the need to plan abandonment of wells in a salt bed, especially if the salt is a seal to a regional artesian system (Warren, 2006).

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(Cont.)

Appendix 3 Descriptions of current operational UK UGS facilities and proposed schemes at the planning or development stage

The following are summaries of various oil or gas field gas storage facilities/operations in the UK.

Currently operational UGS facilities

Depleted Oil and gasfield facilities

Rough Gasfield, (offshore, Southern North Sea) – also Appendix 5

The Rough gasfield storage facility is about 31 km (20 miles) off Withernsea on the East Yorkshire coast, in the southern North Sea. It was originally developed in October 1975 to produce natural gas from the (Early Permian) Rotliegend sandstone reservoir, at around 2750 m (circa 9,000 feet) below the seabed, forming the Rough field.

The gasfield was converted to Britain's biggest offshore gas storage facility in 1985, since when it has been used to store gas under pressure in the depleted Rotliegend reservoir, providing seasonal gas storage capability (Stuart, 1991). It can supply around 10% of Britain's peak demand for gas and currently represents 80% of the UK's gas storage volume. In November 2002, the Rough offshore gas storage facility, linked pipeline and onshore processing plant at Easington in Yorkshire was acquired by Centrica.

Hatfield Moors and Hatfield West (onshore)

The Hatfield Moors gasfield was discovered accidentally (leading to a blow out and fire) during drilling of the Hatfield Moors No.1 exploration well in South Yorkshire in December 1981 (Ward et al., 2003). It was followed by the discovery of the small Hatfield West gasfield in 1983. Gas was encountered at a depth of 484 m (1587 feet) in the Westphalian B Oaks Rock Sandstone Formation. Gas was previously unknown at this stratigraphic level, apart from mine gas, despite the many coal and several oil boreholes that had already penetrated the shallow formation in this area.

Production at the fields commenced in 1986, with both presently 100 per cent owned and operated by Edinburgh Oil and Gas (EOG). Gas was initially supplied to the local Belton Brickworks, although this contract terminated in June 2000.

Devised in 1996, a plan was agreed with Scottish Power in 1998 to use the depleting Hatfield Moors field as a gas storage facility. A 25-year storage contract was agreed and the gasfield was converted to a gas storage facility during 2000. Under the agreement Scottish Power have exclusive rights to inject, store and withdraw gas. EOG receives revenues based upon the storage capacity of the reservoir and for the provision of reservoir management services to Scottish Power.

Although the technique is widely used in France, Germany and the US, Hatfield Moors represents the first onshore UK facility of its kind. Gas from the National Transmission System is compressed before being injected into the porous layers of sandstone circa 1,450 feet underground for storage. The reservoir can store up to 121.8 Mcm (4.3 bcf) of gas at any one time, providing enough gas to meet the peak demands of 250,000 domestic customers.

Some of the gas stored at Hatfield Moors is also used for electricity generation at Scottish Power's gas-fired power stations. Before gas can be returned to the network for delivery to

D2-253 (Cont.)

customer, it must be reduced to the appropriate pressure. A 12 km pipeline provides the link between the storage facility and National Grid Gas's Transmission System.

The Hatfield West field also has potential for conversion to use as a gas storage facility.

Humbly Grove, Hampshire (onshore)

The Humbly Grove oilfield in Hampshire was one of the largest onshore oilfields in the UK. However, as production declined, Star Energy proposed to develop it as a gas storage facility when they announced the major new underground gas storage scheme in early 2003 (received by Hampshire County Council, May 2003: www.hants.gov.uk/decisions/decisions-docs/030910-regunct-R0909111823.html). Having gained planning permission in 2003, work commenced on the site in February 2004 to construct a c. 283 Mcm (10 Bcf) gas storage facility (Fig. 29). The facility was completed in February 2005 and commenced operation on November 4th 2005. The gas injection will also re-pressurise the main oil reservoir, which is the Great Oolite (Middle Jurassic in age) at around 982 m below Ordnance Datum (OD), which will also extend the life of the field from less than 10 years to around 20 years.

The facility required the construction of a pipeline 27 km long and 24 inches in diameter to link the oilfield to the national gas transmission system (NTS) at Barton Stacey near Andover. An additional processing plant has been constructed, together with the installation of compression equipment to pump the gas into the gas store from the NTS and to return the gas back to the NTS after processing.

Salt Cavern Storage facilities

The following are summaries of salt cavern gas storage facilities/operations onshore in the UK (refer Fig. 1):

Holford, Cheshire (Triassic salt)

A former brine production cavern (H 165) in the (Triassic) Northwich Halite Member in the Holford Brinefield, Cheshire, was converted by ICI in 1984 into a gas storage cavern. It was originally leased to Transco, providing diurnal storage and operation has since been transferred to IneosChlor who operate the facility for gas trading.

After the cavern was refilled following a required 10-year inspection, operations resumed in November 2006.

Hole House, Cheshire (Triassic salt)

The Hole House facility, west of the village of Warmingham near Crewe, Cheshire is a gas storage facility developed in the Triassic Northwich Halite Member of the Warmingham Brinefield, which is owned and operated by British Salt. Permissions and consents were originally granted to Aquila Energy Limited in 1995. Commercial operations began in February 2001. The facility was acquired by EDF Trading Limited in October 2002, since when it has been operated by EDF's subsidiary company Energy Merchant Gas Storage (UK) Limited (Beutal & Black, 2005). It is linked to the National Grid gas transmission system.

Phase I of the project saw the construction of two cavities, each of approximately 30 Mcm (c. 150GWh) and a gas processing plant, which became operational in March 2003. The caverns have been designed to provide a highly flexibile facility, capable of supplying 'peak gas'. British Salt use the brine produced during the cavern washing process. The salt is up to 230 m thick and the tops of the caverns are at about 300-400 m depth, slightly shallower than at the Holford and Byley sites (Beutal & Black, 2005). Gas can be delivered at a rate of 2.8 Mcm per day and injected at 5.6 Mcm per day (UK Gas Report, 2005). Phase II saw two additional salt cavities constructed, providing a further 30 Mcm (150 GWh) storage, and an upgrade of the gas processing plant with gas again delivered at 2.8 Mcmd and injected at 5.6 Mcmd. EDF commissioned the first of these two cavities before the end of 2006, and expect to complete the second by the end of 2008 (UK Gas Report, 2005).

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Hornsea (Atwick – Permian salt)

The Hornsea gas storage facility in East Yorkshire was granted planning permission in 1973 and built originally by British Gas Corporation (refer Dean, 1978, 1985). It became operational in 1979, providing storage and peak-shaving supply to the NTS. The facility was bought by US energy company Dynergy in 2001 and sold the following year to the current owners and operators SSE Hornsea Ltd - part of Scottish & Southern Energy plc (UK Energy Report, 2005).

The facility comprises a central processing area and nine salt cavities leached into the main salt of the Fordon Evaporites (Z2) at depths of between circa 1720 km and 1820 m below the surface (Beutal & Black, 2005). Wellhead spacings are >400 m and the size and volume of the caverns is variable due to variations in the thickness of the salt, with the facility providing a total of around 325 Mcm of gas storage space. Gas can be injected at circa 2 Mcmd and withdrawn at up to 18.5 Mcmd (UK Energy Report, 2005).

Teesside – Billingham (Saltholme) and Wilton (Permian salt)

The Teesside Saltfield in south Durham is formed by the (Middle or Main) Boulby Halite Formation (Z3) which overlies the Billingham Main Anhydrite. Salt was extracted at Greatham by controlled brine pumping from around 1822 until at least 1969. As early as 1959, the Northern Gas Board used a solution-mined cavity to store town gas (Notholt & Highley, 1973). More than 100 small brine production caverns were created by ICI to the north of the River Tees at Saltholme and south of the river at Wilton. Some of these have been converted and used for storing light hydrocarbons and the various fluids and gases associated with oil refining since 1960.

In the Teesside area, the top of the Boulby Halite lies at depths of between 274 m and 366 m, deepening eastwards and offshore to over 650 m and is up to 45 m thick (Notholt & Highley, 1973). At least 4 caverns at Saltholme, owned by IneosChlor and leased to Northern Gas Networks (NGN), are owned by IneosChlor & operated by NGN for natural gas. Development and storage commenced 1959-1983, with cavern volumes of 10,000 m^3 – 30,000 m^3 (providing a total net cavern volume of 0.08 Mcm).

SABIC (formerly IneosChlor//Huntsman) have informed this report that there also exists at Saltholme, 18 ex ICI caverns that are in operation for storage purposes (Table 1). There are a further 9 redundent caverns. Development started in the 1950s with storage having commenced 1965-1982. They include 1 'dry' cavity storing nitrogen, 17 'wet' storage cavities containing hydrocarbons ranging from hydrogen to crude oil. In addition, 9 redundant storage cavities, 75 redundant brine wells/cavities (that have never used for storage) and 5 in service brine wells also exist. Injection and withdrawal rates are not available.

Further caverns in both the Saltholme and Wilton brinefields have, for many years, been used to store other liquids and gases such as nitrogen (SembCorp to store BOC nitrogen) and hydrogen (refer Table 1).

Current Applications and Proposals for UGS onshore

A number of applications for both depleted oil and gasfields and salt cavern gas storage facilities are currently at varying stages of the planning application process, or are now in the construction phase. These are briefly outlined below.

Applications to convert depleted oil and gasfields to gas storage

Caythorpe

Caythorpe Gas Storage Limited (CGSL), a subsidiary of Warwick Energy Limited, has applied for permission to build the surface facilities required to convert the existing gas field at Caythorpe into a gas storage facility. This permission has been requested from East Riding of

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Yorkshire Council under the Town and Country Planning Act 1990. Permission to store gas in the underground gas reservoir has also been requested separately from the DTI under the Gas Act 1965 (http://www.warwickenergy.com/gas.htm).

The Caythorpe gasfield lies around 5.5 km west of Bridlington in East Yorkshire between the villages of Rudston and Boynton. The field was discovered in 1987 and commenced production in 1992. As with many of the gas fields in NE England, the reservoir is Permian dolomites. Initially, gas after processing was exported to the Natioanl Grid system, but since 1997 and the installation of a small power station on the site, power has been generated and exported offsite. Warwick Energy acquired the field in 2001 and commenced producing from an additional gas-bearing horizon in 2002. The current facilities comprise one producing well, a gas processing plant and a 9 MW power station, together with a low pressure pipeline which links the site to the nearby gas grid. To date, field operations have been without incident.

The Caythorpe Gas field is located in Licence area PL 234 in Yorkshire, which expires in 2017. To date, two wells have been drilled to define a single geological structure with fault-dip closure. The first well (C-1) was drilled by the original operator, Kelt UK Limited (Kelt) in 1987, on the edge of the accumulation. The second (C-2) was also drilled by Kelt in 1989 from the same surface location, but the borehole was deviated up to 44° to a crestal location to the west of C-1 (IEA, 1999). Two gas-bearing reservoirs of Permian age have been tested: one in the Kirkham Abbey (Dolomite) Formation (KAF - Permian Zechstein dolomitic and oolitic limestones) at 1748 m BOD; and the other in the Rotliegend sandstone formation at 1829 m BOD. The Rotliegend is a regionally-extensive formation and it is the main producing reservoir in many of the offshore gas fields in the southern sector of the UK North Sea. Over 30 m of core was collected from the Rotliegend in wells C-1 and C-2, providing detailed information on the reservoir characteristics. The reservoir consists of two sections, with the upper part having the better reservoir properties (permeability more than 100 mD) than the lower section (20 mD). No core was collected from the KAF (IEA, 1999).

The initial reservoir pressures were determined from the Repeat Formation Tester (RFT) tool data, with values obtained for the Rotliegend of 2,969 psia, and 2,835 psia for the KAF (IEA, 1999). The KAF was tested for 30 hours in well C-2 at up to 8 Million Standard Cubic Feet per Day (MMscfd) from a 13m interval. The reservoir is a tight dolomite with production from a natural fracture system. The gas had an H_2S content of around 5 parts per million (ppm). Two separate production tests were completed in the Rotliegend in well C-2. A lower section near the gas-water contact (GWC) was tested at 1.0 MMscfd for 4 hours from a 3 m interval. The section near the top of the reservoir was subsequently put on extended test from a 3 m interval at rates up to 10 MMscfd. The Rotliegend gas has no reported H_2S content. Well log interpretation and core analysis indicates an average porosity of 15% for the KAF and 18% for the Rotliegend and average water saturation of 40% for the KAF and 31% for the Rotliegend.

The Rotliegend has an original GWC at 1870 m BOD with a mapped closure of approximately 213 acres or 86 ha (IEA, 1999). No detailed map of the KAF has been made publicly available.

The field was originally explored, developed and produced by Kelt from 1983 to February 1997. Gas production has been from the Rotliegend reservoir alone, with well C-2 being the only producing well in the field. The KAF reservoir is isolated by the well completion. The well produced at rates up to 10 MMscfd mainly during the winter months. It has required two sand clean-out jobs to assist production performance, no other production problem issues being reported. Produced condensate has averaged around 5 Bbl/MMscf.

The field was shut-in from March 1996 until November 1997, during which time IEUKL secured the transfer of the licence and then obtained local planning and DTI approval for revisions to the development plan to allow onsite power generation. That plan included producing the reservoirs to a lower abandonment pressure than proposed originally due to the new surface production configuration that could operate to a lower pressure (60 psig versus 295 psig). The project approval covers power generation operations up to 2009. IEUKL operated and produced the field

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at rates up to 1.78 MMscfd from December 1997, with flowing wellhead pressures between 400 and 980 psig.

Production from the field has now declined, however, and the good reservoir properties in the KAF (c. 1748 m to 2090 m depth) and Permian Rotliegend (Leman equivalent) sands (c. 1829 m to 2135 m depth) mean that gas storage represents a viable future for the gasfield. Development would require a site extension to accommodate the additional gas processing facilities and compressors for the gas storage project. In addition, a further six wells would be required and these would be located at a separate site nearby. A new 4.4 km high pressure pipeline would also be needed, laid in the same pipeline corridor as the existing low pressure line, connected to the National Transmission System. The existing low-pressure line will be retained to provide fuel for the power generation facilities. A new pipeline will connect the storage facility and the new wellsite.

Studies indicate that the gas field has a total usable storage capacity of 210-212 Mcm (7.5 Bscf) offering the potential for short term withdrawal and injection rates of up to 8.5 Mcm/d (300 Mscf/d) or the capability of producing an average 4.7 Mcm/day (167 Mscf/d) over a 45 day period (http://www.warwickenergy.com/reservoir.htm). The redevelopment plan would extend operations on the site for an estimated 25 further years.

The hazardous substances consent application was accompanied by a full Environmental Statement (ES) for the proposed development, which drew upon the results of a number of environmental and technical surveys and studies commissioned by CGSL. A public meeting for the project was held in June 2005, at which concerns were expressed by some local residents about possible safety issues. The planning application for the surface facilities for the scheme was considered at a meeting of the planning committee of East Riding of Yorkshire Council on 22 June 2006, at which the committee rejected their planning officer's recommendations that the application be approved, citing amongst other things, safety reasons and the lack of national need. Warwick/CGSL immediately stated their intention to appeal the decision and a public inquiry is due to commence on 24 April 2007 (Malcolm Wicks, Minister of State [Science & Innovation], Department of Trade and Industry (now Department for Business, Enterprise and Regulatory Reform): http://www.theyworkforyou.com/wrans/?id=2007-01-25b.110513.h).

Welton

The Welton oilfield was discovered in 1981, although oil exploration has taken place in the area since the 1950's and has produced oil (and associated gas) since 1984. Production has now reached the mature stage as reservoir pressures and oil production declines. The main trap is provided by an anticlinal structure with fault closure to the east. The main reservoir is provided by late Namurian to early Westphalian channel and interchannel sandstones deposited in a large delta system. The depth to the main reservoir interval in the crest of the anticline is mapped at circa 1360 m below sea level. Oil density is 36° API and initial reservoir pressure was 2230 psi. Porosities and permeabilities lie in the range 9.5-12.5 % and 1-500 mD respectively (Rothwell & Quinn, 1987).

The proposals involve the construction of a 24" (609.6 mm) diameter steel pipeline, mainly located underground, from an existing national gas pipeline system near Holton cum Beckering (to the north of Wragby) which will link to the existing Star Energy Gathering Centre to the northeast of Reepham, and southeast of Sudbrooke. At the Gathering Centre the gas would be pumped into the existing depleted underground oil reservoir during periods of low gas demand, where under pressure it would assist in the recovery of the residual oil resources, but would also act as a substantial gas storage facility (refer Table 1). The stored gas would be reintroduced back into the national system during periods of high demand.

West Lindsey District Council at an Extraordinary Meeting of the Council on 27th May 2004 resolved to recommend "that Lincolnshire County Council be strongly urged not to grant planning permission", citing public safety fears as the main point of concern. Subsequently,

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County Council planners recommended planning permission be granted for the proposal, subject to certain conditions. No major concerns, in relation to the project were expressed by, the Environment Agency, English Nature or the Health and Safety Executive. However, at a meeting on 22 February 2006, Lincolnshire County planning committee concluded that planning application "was minded to be refused", citing local fears over health and safety and claiming the proposals would represent an intensification of industrial development in open countryside, contrary to planning policy. The recommendation was that the proposal be called in for consideration and determination only after a Public Inquiry.

Star Energy immediately stated that they will appeal the decision to the Office of the Deputy Prime Minister believing that the company has grounds for appeal due to the fact the council's planning officers' report recommended approval of the project. It seems likely, therefore, that the situation will be resolved either at a Public Inquiry at some point in the future, or that the application will test the provisions of 1966 Gas Act in securing the relevant permissions to develop the gas storage facility.

Saltfleetby

The Saltfleetby Gas-condensate field is located on the East Lincolnshire coast between the Welton Oilfield of the Midlands oil province and the offshore gasfields of the southern North Sea (SNS). It was discovered in 1996 and commenced production in 1999. In January 2006, Wingas Storage (UK) Ltd (WSUKL) submitted a planning application to Lincolnshire County Council to convert the producing Saltfleetby Gasfield on the east Lincolnshire coast to a gas storage facility. The gasfield has been producing gas and associated condensate since December 1999 and is now reaching the mature stage of production, with reservoir pressures and gas production declining. The suitable geological conditions (reservoir and trap) mean that it is now being considered for conversion to use as an underground gas storage (UGS) facility.

The crest of the structure is mapped at circa 2234 m below sea level, with the trap being mainly the result of four-way dip closure, although faults provide seal and closure in a number of areas (Hodge, 2005). The reservoir rocks are late Namurian to early Westphalian channel and interchannel sandstones deposited in a large delta system. Initial reservoir pressure was 3566 psia, with a present day pressure gradient of 0.112 psi/ft. Porosities and permeabilities lie in the range 9.5-12.5 % and 1-10 mD respectively.

Gainsborough/Beckingham

Star Energy acquired the Gainsborough-Beckingham Oilfield in the East Midlands as part of its purchase of Pentex in July 2005 and is looking into its potential use for gas storage. Preliminary subsurface and development studies have been carried out and these indicate that the field is suitable for use as a gas storage facility with the potential to provide a seasonal storage capacity of 227 – 240 Mcm (8 – 8.5 bcf), with a deliverability of 3.5 Mcmd.

The Gainsborough-Beckingham Oilfield comprises a number of distinct accumulations, due mainly to the lateral and vertical (stacked) distribution of reservoir sandstones at a depth of approximately 1375 m. The Gainsborough section of the field was discovered in 1959, with production also having commenced in 1959. The Beckingham portion of the field was discovered and commenced production in 1964. A closely associated field, Beckingham West, was discovered in 1985 and commenced production in 1986. The reservoir rocks are late Namurian to early Westphalian channel and interchannel sandstones deposited in a large delta system.

Oil gravity at Beckingham West is 35.64° API, with original reservoir pressures in Beckingham of around 1400 psi (Gair et al., 1980).

In addition to the Gainsborough Oilfield, Star Energy is also undertaking further studies of other fields in the Pentex portfolio (many of which are in the East Midlands), to assess their suitability as potential gas storage reservoirs.

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Albury

The Albury oil and gasfield in the Weald Basin, southern England, was discovered in 1987 and commenced production in 1994. It is currently operated by Star Energy, producing gas, which is used to generate electricity on site from two 1MW generators.

Albury is one of a number of depleting oil and gasfields in southern England operated by Star Energy and which, following Humbly Grove, are under consideration for conversion to storage facilities. Lower Cretaceous glauconitic sands and limestones of the Lower Purbeck Beds form the reservoir rock, present in tilted fault blocks at around 625 m below sea level (Trueman, 2003). Oil density is 31° API, initial reservoir pressure was 1100 psi and porosities and permeabilities are of the order of 25.3 % and 1067 mD respectively.

Development at Albury is anticipated to take place in two phases, with the projected completion of the facility somewhere around 2010.

In May 2006 Star Energy announced an agreement to purchase Edinburgh Oil and Gas's 37.5% share of the Albury gas field and its 25% share of the Storrington oilfield. The acquisition, which is subject to regulatory approval, will now give Star Energy 100% ownership of both fields.

On the 26th July 2007, Star Energy Group plc submitted its preliminary submission for a Storage Authorisation Order for its Albury Phase 1 gas storage project to the Department for Business, Enterprise & Regulatory Reform (Star Energy, 2007).

The application is for permission to store up to 8.2 bcf (billion cubic feet) of natural gas in the existing, partially depleted Albury gas reservoir.

Bletchingley

The Bletchingly gas discovery, lies along the northern boundary of the Weald Basin in southern England, to the south of the Palmer's Wood oilfield in acreage operated by Star Energy. Gas was discovered in 1965 with the drilling of three exploration wells, flowing at a rate of 4 million cubic feet per day (Mcf/d)/0.113 million cubic metres per day (Mcm/d) from Jurassic (Corallian) limestones. Recoverable reserves at the time were estimated at 2.4 bcf/68 Mcm (Huxley, 1983).

The gasfield is formed by Upper Jurassic Corallian Limestone present in a faulted dome at around 930-1143 m below sea level (Trueman, 2003). Initial reservoir pressure is not available but porosities and permeabilities lie in the range 10 % and < 1 mD respectively.

The discovery and immediate license acreage in which the discovery lies, are currently under evaluation by Star Energy for their suitability to provide a gas storage facility, with storage potential currently estimated to be up to 900 Mcm. If the results are successful and planning is approved, it could be operational by 2009.

Storrington

The Storrington Oilfield lies in the Weald Basin, southern England and is operated by Star Energy. The reservoir rock is formed by sequences (limestones +/- sandstones) of the Great Oolite Group, present within tilted fault blocks at around 1152 m below sea level (Trueman, 2003). Oil density is 39.04° API, initial reservoir pressure was 1758 psi and porosities and permeabilities lie in the range 13 (6-26)% and 5 (0.1-2000) mD respectively.

Applications and plans to develop salt caverns for gas storage

Byley Cheshire (Triassic salt)

The Byley gas storage scheme is being developed in the Triassic Northwich Halite Member, around the Drakelow Lane area that lies towards the southern end of the Holford Brinefield, owned by IneosChlor. It is also referred to as the Holford storage scheme. Planning consent was not granted when Scottish Power originally applied in 2002. Scottish Power appealed the

D2-253 (Cont.)

decision, which led to a Public Inquiry in late 2002. Following the Inspector's decision and after an intervention in the national interest by the then Deputy Prime Minister John Prescott, consent was granted in May 2004. It was confirmed after a legal challenge against the intervention failed in December 2004, and work commenced clearing and preparing the site in March 2005. In July 2005 Scottish Power sold their rights to Eon UK for around £96 million. In August 2005 work on the infrastructure commenced and Eon began the brining process for the caverns in the summer of 2006. The facility will be connected to the national transmission system (NTS) by a 4 km long pipeline.

IneosChlor will undertake the solution mining, with Eon leasing the caverns and owning/operating the infrastructure. The plans are for eight cavities, with wellhead spacings of 280 m, providing a storage capacity of around 170 Mcm, with a deliverability of 16 Mcmd (emptying in around 10 days) and injectability of 8 Mcmd (filling in 20 days). Phase 1 cavern washing commenced in summer 2006 and will provide about half the space (4 caverns) and estimated completion is by 2008. Estimated completion of the second phase (and full capacity achieved), is by 2010 (UK Gas Report, 2005). Cavern tops will be between 630 m and 730 m below ground (Beutal & Black, 2005) and it is noted that latest designs indicate the base of the caverns are likely to be at the level of the 'Thirty Foot Marl', which will form the cavern 'sump'. Earlier designs had indicated that the 'Thirty Foot Marl' would lie at a level between half to two thirds of the way up the caverns (e.g. Beutal, 2002).

Stublach, Cheshire (Triassic salt)

The Stublach gas storage facility is located in the Holford Brinefield between Drakelow Lane and Lach Dennis. The site is about 2 km from Byley. The proposal to develop the Stublach facility, comprising 28 caverns in the Northwich Halite, will provide around 540 Mcm capacity. The cavities will be bell-shaped, approximately 100 metres in height, with their tops at around 550 metres depth.

INEOS Enterprises Limited submitted the planning application to Cheshire County Council in December 2005. Following a council meeting, planning permission was granted in June 2006 (Cheshire Council, 2006), subject to the Government not 'calling it in' (requiring further consultation and Public Inquiry). In July 2006 the DTI (now DBERR) "confirmed that whilst recognising that each case must be decided on its own merits, the Energy Markets Unit of the DTI believes that new gas storage projects would be invaluable from an energy policy perspective". In December 2006, the Government confirmed that it would not be calling for an Inquiry signalling the go ahead for development. Hazardous substance consent was also granted. The project is thus fully consented and development can commence. The statements by Council members following the meeting said that "As far as [the Council] are concerned this application is a very difficult thing to refuse on local grounds"....."Byley was a long time ago and things are now vastly different."....."Members felt that the need for gas storage had been more clearly identified than when considering the Byley application....."And today felt that that national need was more important than all other planning considerations." However, Council Members also resolved that should planning permission be granted, a legal agreement be entered into with the applicant and that over 80 stringent planning conditions would be required.

In late August 2007, it was announced that Gaz de France had signed an agreement with Ineos Enterprises for the commercial development of the proposed salt cavern storage facility (GDF, 2007). INEOS will continue to be involved in the development of the facility, which will involve the construction of up to 28 caverns by solution mining. The brine will be used for industrial purposes. The first phase of the Stublach gas storage facility remains on track to commence cavity development in 2009, with commissioning of the first caverns anticipated in 2013 and the remaining caverns developed through to 2018. The Group will operate the infrastructure under a 30 year lease agreement running until 2037.

D2-253 (Cont.)

Preesall/Wyre, Lancashire (Triassic salt)

Canatxx Gas Storage Ltd is planning to develop a salt cavern storage facility in the Preesall Halite of the Lancashire saltfield, which was worked by both mining and solution mining until the final brine extraction operation closed in 1993 (Landless, 1979; Wilson & Evans, 1993; BGS, 2006). In 2003, Canatxx submitted a planning application to develop up to 24 caverns, providing storage space for between 1200 and 1700 Mcm of gas, in the unworked Preesall Halite to the west of the existing brinefield beneath areas of the River Wyre Estuary. Pre-existing salt cavities arising from the brine extraction process have already been used by ICI for the storage of hazardous materials. Limitations exist on large-scale development of any sort due to the salt coming to crop in the east and south and by large areas of new housing in areas of unworked halite to the north of the brinefield.

The unworked halite is between 140 m and 240 m thick and the top of the caverns will be at depths between 220 and 425 m (refer Heitmann, 2005). Caverns, the heights of which will be variable and dependent upon local geological conditions, will be accessed via S-shaped deviated wells from clusters of wellheads located elsewhere in the saltfield. The facility has an anticipated operational life of 25 years and will be connected to the National Transmission System by a pipeline, with deliverability estimated at as much as 114 Mcmd.

The planning application received strong opposition, both from the local planning authority and local residents and in December 2004, Lancashire County Council voted to oppose the scheme. The application went to a Public Inquiry that ran from October 2005 to May 2006, when the number of cavities was reduced to 20 providing storage capacity for up to 1600 Mcm (c. 1.2 million tonnes: Heitmann, 2005; Humphries & Barrett, 2005).

On 17th October 2007 following the Inspector's report, Hazel Blears, Secretary of State for Communities and Local Government, announced that the Government was dismissing the Canatxx appeal and refusing Planning Permission and Hazardous Substances Consent for development of a natural gas storage facility. The plans have been rejected mainly on the grounds of the impact on the local environment and on safety issues (http://www.gnn.gov.uk/Content/Detail.asp?ReleaseID=323317&NewsArea ID=2).

D2-253 (Cont.)

Isle of Portland, Dorset (Triassic salt)

In April 2005, Egdon Resources announced plans to develop a high deliverability salt cavern storage facility in Triassic salts beneath the Isle of Portland in Dorset. In February 2005 Portland Gas Limited was established as a wholly owned subsidiary of Egdon Resources. Portland Gas signed an agreement with Portland Port Limited in April 2005 to lease a 5 ha 'brownfield site' at the former naval base HMS Osprey for a period of up to 90 years.

Work began, with German cavern design experts KBB, on a feasibility study on the potential capacity and operating parameters for gas storage facility in the Triassic salts of the Weymouth and Portland area. A seismic reflection line was acquired in May 2005 and an exploration well (Portland No.1) was drilled and completed in June 2006. This proved the presence and thickness of the Triassic saliferous beds (Egdon, 2006a). Initial estimates were that the storage facility would have potential to provide up to 10% of the UK gas demand on a typical winter day and provide a storage facility for 1% of the UK annual consumption. Initially, the storage facility was planned for development in three phases of six caverns. Each phase would bring a working storage volume of 330 Mcm. The project has been designed with gas export capabilities to the national gas grid increasing from 18 to 54 Mcmd through the three phases. In September 2006 a technical feasibility study confirmed the potential for cavern storage over an area of approximately 20 km^2. The revised plans had 14 cavities storing up to 1000 Mcm of natural gas. The injection and withdrawal rates of 20 Mcmd would permit the filling and emptying of the entire storage volume in 50 days (Egdon, 2006b). The caverns will be at depths greater than 2100 m and up to 100 m high (refer Fig. 57). The plans are that they will be operated in brine

compensated mode i.e. brine will be stored and used to compensate gas injection and withdrawal in the caverns (Egdon, 2007a).

As a result of the feasibility study, the Environmental Statement, planning and pipeline construction authorization applications were submitted in March 2007 (Egdon, 2007a). Six planning applications were submitted and included that for a brine well site at Stafford Farm, near West Stafford, adjacent to the pipeline. This will be used to store the brine used to compensate gas injection and withdrawal in the caverns. A separate pipeline will run to Portland from the site. If planning approval is granted during 2007, it is anticipated that initial storage capacity would be available during the winter of 2011, with full capacity being available during 2013 (Egdon, 2006b, 2007a).

King Street, Cheshire (Triassic salt)

NPL Estates, through its wholly-owned subsidiary King Street Energy Ltd, is proposing to develop a salt cavern gas storage facility near Rudheath in Cheshire (NPL, 2007). The site will be to the north of other proposed sites at Byley, Holford and Stublach (refer Fig. 1).

The proposed site, known as the King Street development, was formerly part of the operational Holford brinefield and has an existing planning consent for brining and underground waste disposal. It is proposed to store gas in underground cavities leached in the salt layer some 400m below the surface. The area is underlain by a thick salt layer (the Northwich Halite), which coupled with the overlying marl, is anticipated to make conditions possible for gas storage. The site will require further detailed geological investigation involving drilling and other exploration activities.

To develop the facility, NPL is proposing to construct nine cavities, each with a volume of 400,000 m^3. It is reported that up to 216 Mcm of gas will be stored in total, of which up to 126 Mcm will be working gas during normal operations. The supporting gas processing facility will be located on the former Associated Octel Site on the northern edge of the Holford brinefield near Lostock Gralam. The site extends to about 16 acres (16.5 ha) and is remote from the local community. Once completed the wellheads will be secured in small compounds and fully screened from the surrounding area.

NPL proposes to construct a twin pipeline system between the Mersey Estuary and the King Street site to supply leaching water and to discharge the weak brine. Other gas storage projects in the district take water from the local rivers and pass the brine to process users. However, the rivers have little remaining abstraction capacity and there is no scope for local companies to process more brine for some time to come. The pipeline system will include pumping stations at both ends of the pipeline and one at approximately the halfway point. These facilities will be largely underground. There will be a need for an intermediate storage tank system at the King Street end to provide a buffer between the brining and pipeline operations.

North/South Aldbrough (Permian Salt)

Plans for an underground gas storage facility to the south of Scottish and Southern Energy's (SSE's) Hornsea (Atwick) gas storage site, at Aldbrough in East Yorkshire have been ongoing since 1997. At that time, two separate planning applications were submitted, one by British Gas at Aldbrough North (six caverns) and a second by Intergen at Aldbrough South (three caverns). Both applications were rejected, due to strong local objections and a further application was also refused precipitating, in 1999, the first Public Inquiry to be held into the planning and siting of such facilities (Beutal & Black, 2005). The Inquiry resulted in the Government granting permission to both BG and Intergen to proceed with plans to develop the two facilities.

In 2001 ownership of Aldbrough North passed to Dynergy with its acquisition of BG assets, which they then sold to SSE in 2002. In 2003 Intergen sold Aldbrough South to Statoil. The new owners combined the two projects in late 2003. The joint venture, estimated to cost £225 million, will generate a total storage capacity of around 420 Mcm, with SSE owning 280 Mcm storage

D2-253 (Cont.)

space and Statoil 140 Mcm. Injectability is thought likely to be around 20 Mcmd and deliverability circa 40 Mcmd (UK Energy Report, 2005).

Site work commenced in March 2004 and leaching of the first of the nine planned caverns began in March 2005. Cavern tops will be between 1800-1900 m below ground, with the first five caverns expected to be ready for commercial use around October 2007. The remaining four are likely to be completed by 2009 (UK Energy Report, 2005). The plant will be operated remotely.

North of Aldbrough (Permian Salt)

In mid January 2007, E.ON UK submitted a planning application to build underground gas storage facility to the north of Aldbrough in East Yorkshire. During 2006, E.ON had carried out geological investigations to confirm the area's suitability for the facility.

The proposed facility is reported to provide a total working gas capacity of 420 million standard cubic metres of gas. The planning application was submitted to East Riding of Yorkshire Council with, it was hoped, a decision on the proposals reached by mid 2007. To date, there has been no announcement made on any decisions.

If the scheme is approved, construction is expected to start late in 2007 with the first phase operational in 2010. Completion of all work is planned by 2013.

Northern Ireland (Triassic and Permian salts)

Interest is being shown in the potential for developing salt cavern storage facilities in salts of both Triassic and Permian age in the Larne Basin, Northern Ireland. As described elsewhere in the report, the main salts are of Triassic age and have been proved in the Larne 1 and 2 boreholes (Penn, 1981; Mitchell, 2004).

On 24th July 2007, Egdon Resources Plc announced that a wholly owned subsidiary, Portland Gas NI Limited was being granted an exploration licence from The Crown Estate to evaluate the suitability of the Permian salt sequence, below Larne Lough, County Antrim, Northern Ireland to create caverns to store natural gas (Egdon 2007b). The salt sequence was proved by the Larne No.2 borehole, drilled in 1981. Close to the docks in Larne, this borehole proved a 113 metre thick sequence of salt near the top of the Permian sequence, at a depth of 1688 metres. During October 2007, Portland Gas NI Ltd plans to undertake a seismic reflection survey, which it is hoped will confirm the extent and suitability of the salt sequence proved in the old borehole, for the possible development of gas storage caverns.

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Appendix 4 Seismicity - Earthquake magnitude/EMS-98 intensity comparison.

Earthquake magnitude/EMS-98 intensity comparison

Magnitude (Richter)	Intensity	Description
1.0 – 2.9	I	*I – Not felt* Not felt, even under the most favourable circumstances
3.0 – 3.9	II – III	*II – scarcely felt* Vibration is felt only by individual people at rest in houses, especially on upper floors of buildings *III – Weak* The vibration is weak and is felt indoors by a few people. People at rest feel a swaying or light trembling
4.0 – 4.9	IV – V	*IV – Largely observed* The earthquake is felt indoors by many people, outdoors by very few. A few people are awakened. The level of vibration is not frightening. Windows, doors and dishes rattle. Hanging objects swing *V – Strong* The earthquake is felt indoors by most, outdoors by few. Many sleeping people awake. A few run outdoors. Buildings tremble throughout. Hanging objects swing considerably. China and glasses clatter together. The vibration is strong. Top-heavy objects topple over. Doors and windows swing open or shut.
5.0 – 5.9	VI – VII	*VI – Slightly damaging* Felt by most indoors and by many outdoors. Many people in buildings are frightened and run outdoors. Small objects fall. Slight damage to many ordinary buildings e.g. fine cracks in plaster and small pieces of plaster fall. *VII – Damaging* Most people are frightened and run outdoors. Furniture is shifted and objects fall from shelves in large numbers. Many ordinary buildings suffer moderate damage: small cracks in walls; partial collapse of chimneys.
6.0 – 6.9	VII – IX	*VIII – Heavily damaging* Furniture may be overturned. Many ordinary buildings suffer damage: chimneys fall; large cracks appear in walls and a few buildings may partially collapse *IX – Destructive* Monuments and columns fall or are twisted. Many ordinary buildings partially collapse and a few collapse completely.
7.0 and higher	X or higher	*X – Very destructive* Many ordinary buildings collapse *XI – Devastating* Many ordinary buildings collapse *XII – Completely devastating* Practically all structures above and below ground are heavily damaged or destroyed.

D2-253 (Cont.)

Appendix 5 Underground Fuel Storage Incidents

Appendix 5 provides a review of underground fuel storage incidents found and described in Evans (in press) following a review of available literature and articles published on the internet (world-wide web). From this work the information and tables in Chapter 9 have been compiled.

European salt cavern storage incidents leading to cavern closure

The following descriptions summarise European examples of gas leaks at salt cavern facilities and instances of cavern closure arising from instability and volume loss, where no gas/product leakage occurred.

Teutschenthal, East Germany

At Bad Lauchstädt near Teutschenthal, to the SW of the city of Halle, Germany, an underground gas storage facility was developed in a salt cavern within the Zechstein (Permian) Stassfurt Rock Salt (Katzung et al., 1988). The facility lies in an area of sparsely populated countryside. Hereabouts halokinesis has led to markedly variable salt thicknesses with large salt pillows formed (Fig. 30). Overlying the Zechstein salt is up to 400 metres of 'Bunter' (Triassic) sandstones (the Volpriehausen Sandstone) and a thin Quaternary cover, comprising Pleistocene sands and gravels with marly till. The salt cavern, used to store ethylene, was located in the region of thicker salt and was approximately 150 m high, the top being at circa 550 m below ground and the base at just below 700 m.

On March 29th 1988, approximately one hour prior to the eruptions seen at surface, a rapid loss of pressure in the salt cavern was detected. The first eruption and release of a mixture of ethylene and water occurred about 50 m away from well #5. It was followed by several more in parallel rows that formed a 2 km long NW trending line of eruptions (Fig. 30). At the same time, major vent sites also developed about 250 m south of well No.5, in the vicinity of well No.6. The ventings of ethylene continued for several days, decreasing in intensity until the pressure in the cavern had reduced and between 60% and 80% of the product had escaped. The migrating ethylene/water mix once near surface caused doming of the ground, leading to cracks in buildings and tilting of concrete road slabs. Circular and elongated craters and fissures developed as the mix escaped to the air.

An area of approximately 8 km^2 was evacuated whilst the situation was monitored, however, it was decided not to evacuate parts of Teutschental town. Investigations revealed that the cavern remained intact throughout the incident and that there had been no failure of the well casing at that level (Katzung et al., 1988). Ethylene was found in a drinking water well close by, which suggested leakage into an aquifer at depths of between 100 and 140 m. A faulty well casing connection at 111.8 m was subsequently found, which had permitted ethylene to migrate into the lower part of the Volpriehausen Sandstone aquifer, which is overlain by an impermeable horizon. From here the escaping ethylene, migrated laterally up-dip to the WNW until it encountered a reverse fault. This formed a vertical barrier and effectively ponded the ethylene, which then continued to migrate upwards to the NW. Eventually it breached the overlying caprock and escaped into the upper part of the Triassic Volpriehausen Formation aquifer. It migrated rapidly through this, laterally to the base of the Pleistocene deposits, aided it would seem by 'linear zones of disruption' (faults?) within the aquifer. Continued inflow and rising pressures caused doming of the Pleistocene deposits until finally confining pressures were exceeded and the mixture of water, ethylene and entrained boulder clay broke through to the ground surface, creating a linear series of both circular and elongated craters (Fig. 30).

D2-253 (Cont.)

Tersanne, France

Between November 1968 and February 1970, a pear-shaped cavern, referred to as Te02 (Bérest & Brouard, 2003), was leached in salt deposits at Tersanne in SE France (Fig. 21). This represented the first such storage facility in France (Thoms & Gehle, 2000). The top of the cavern was at a depth of about 1395 m, with the bottom at approximately 1500 m, although significant insolubles collected at the bottom of the cavern, such that the effective base of 'free' cavern space was at a depth of around 1470 m. The initial usable volume was 91,000 m^3 +/- 2700 m^3 (Bérest & Brouard, 2003). Dewatering and filling of the cavern commenced in May 1970 and was completed by November 1970. The cavern operated for nine years, during which time the average pressures were high, but operation of the cavern meant frequent and significant pressure variations (Bérest & Brouard, 2003). Such operating conditions resulted in a 30-35% volume reduction by July 1979.

The facility is still operational (operators; Gaz de France: http://www.igu.org/html/wgc2006/WOC2database/Excel/Report_Tab_Summary_UGS_Key_Data_2006_in_operation_english.xls) and has recovered much of the volume loss (Thoms & Gehle, 2000; Warren, 2006). Presently, Gaz de France operate other salt cavern storage facilities at depths of 1400 m in the same salt deposits of the Tersanne area. Around 14 storage wells/caverns are in operation, with gas stored at pressures of between 80 and 240 bar and providing 204 mcm^3 working gas volume.

Kiel, Germany

A gas storage cavern (Kiel 101) was leached out in impure halite deposits (haselgebirge facies) of Permian age at depths between 1305 m and 1400 m at Kiel in Germany (Fig. 31; Coates et al., 1981). The high insolubles content of the halite meant that of the initial 68 000 m^3 volume, the effective volume was reduced to less than 60% of the total (c. 40,800 m^3). Pumping to remove brine from the cavern commenced in November 1967 and roof breaks were noted after only 5 days (Bérest & Brouard, 2003). Useable cavern volume then stood at around 36,600 m^3, but after 35 days operation, sonar scans indicated had fallen by around 12% (down to 32,100 m^3). A further volume loss of 6% (1900 m^3) occurred over the next 5 months (Bérest & Brouard, 2003).

The cavern was operated at between 80-100 bar pressure until at least 1971 and is believed to have been one of the caverns used to store town gas (60% - 65% hydrogen) since 1971 (Padró & Putsche, 1999; Leighty et al., 2003).

Viriat, France

Sketchy details of an incident at a salt cavern storing ethylene have been obtained (AEA, 2005; Nigel Riley, HSE 2005 pers com). The incident in September 1986, apparently related to rupture on a compressor unit that released a gas cloud. No further details are available.

American and Canadian salt cavern storage incidents

In the USA, solution-mined salt caverns have, for many years, been used for storage by the petrochemical industry. More recently they have been used for the storage of natural gas and liquefied petroleum gases (propane and butane). Figures released by the Energy Information Administration (http://tonto.eia.doe.gov/dnav/ng/ng_stor_cap_dcu_nus_a.htm) show that the US operates the highest number of UGS facilities, with 394 (although 37 were classified as marginal at the end of 2005 – that is no injections or withdrawals, or withdrawals only were made; EIA, 2006). This figure compares with 410 underground natural gas storage facilities in operation in 1998 and a peak figure of 418 operational sites in 2001. Of these 30 (c. 7%) were salt cavern facilities. By 2003, there were 391 underground natural gas storage facilities. Of these, salt caverns constituted 8% of the total.

Two types of salt deposits of three different ages occur in the USA and Canada (Fig. 25), namely bedded salt and salt domes. The former occur in layers in a number of basins across the USA and

D2-253 (Cont.)

into Canada, bounded on the top and bottom by (often impermeable) competent rock formations. In Canada salt was deposited during Devonian times in the Western Canada Sedimentary Basin, forming the Lotsberg and Prairie evaporite formations. These have been extensively exploited, as have the most wide spread bedded salts in the USA, which are of Permian age. These deposits contain significant quantities of impurities and are interbedded with variously impermeable anhydrite, shale, and dolomite beds. The Middle Jurassic Louann Salt (e.g. Seni & Jackson, 1983) is a thick bedded, homogenous halite deposited from hypersaline waters that developed in restricted marine basins across much of the area of the present day Gulf of Mexico, including onshore Texas, Louisiana and Mississippi (Jackson & Seni, 1983; Seni & Jackson, 1983; Wescott & Hood, 1994). These basins developed during late Triassic-Early Jurassic rifting, as the North American Plate drifted away from the African and South American plates.

The Louann Salt reaches thicknesses in excess of 1500 m in the basin centre and forms the second type of salt deposit; halokinetic structures that include salt domes, diapirs and walls. These structures are most abundant in the East Texas and Gulf Coast area. The salt first moved during the early period of basin formation (Jurassic-Early Cretaceous) and continued to move at different times thereafter.

American incidents involving storage facilities constructed in Mid-Jurassic Louann salts of the American Gulf Coast area

Eminence, Louisiana (USA)

Located in Covington County, Mississippi, the Eminence salt dome represents a large salt piercement structure, the top of which lies at about 745 m below ground level (Halbouty, 1979). Strictly, the Eminence facility is not associated with any release of gas, but is included here as it experienced loss of volume due to salt creep, which led to its closure.

In 1970, following extensive studies, Transcontinental Gas Pipe Line Corporation selected the Eminence Salt Dome, as the location for the first solution-mined salt cavern facility constructed specifically for the storage of natural gas in the USA (Allen, 1972). The site was chosen because the dome was near to Transco's natural gas pipeline, the salt was relatively shallow, there was a ready supply of freshwater with which to leach the salt and the Wilcox Sands provided an aquifer for brine disposal (Fig. 32).

Two caverns between 1740 m and 2050 m apart, each with capacities of just over 1,100,000 bbl, were constructed using solution wells, which were spudded in August and November 1968. Leaching operations were completed by January 1969. A further two caverns followed, to provide a storage volume of 251.8 Mcm (Coates et al., 1981).

The caverns, each served by a single well, were operated "brine free", i.e. no brine was present in the cavern, natural gas being injected into the caverns under pressure. Gas is withdrawn from the caverns due to the pressure, not by pumping brine into the cavern. Maximum operating storage pressure was around 27.2 MPa (3,950 psi), although the well casing and shoe assembly was tested to 5000 psi, whilst wellhead equipment with 34.5 MPa (5,000 psi) working pressure was installed. Minimum operating pressures were around 6.9 MPa (1000 psi).

In 1970, cavern tops were at around 1725 m and the bases at about 2000m. By 1972 the cavity bottom in cavern No.1 had risen by around 46 m, with a total closure of 40% of the initial volume in just two years (Baar, 1977; Bérest & Brouard, 2003).

The facility operated for over 10 years, but the loss of cavern capacity appeared to lead to its closure in the early 1980s. However, it is reported that volume was regained and the facility is currently in operation (Warren, 2006). The cause of the volume loss was due to having operated at pressures too low to maintain cavern walls.

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Petal City, Mississippi (USA)

The Petal City gas storage facility is located near Petal City in Forrest County, Mississippi (Fig. 25; EIA, 1995). Petal Gas Storage LLC (a subsidiary of GulfTerra Energy Partners, LP) operated the facility in 2004, with a contract to provide Southern Natural Gas with storage space. The facility, with interconnectors to the Tennessee Gas Pipeline, Gulf South Pipeline and Hattiesburg Gas Storage facility, comprises at least 7 caverns providing up to 83.2 Mcm of high-deliverability natural gas storage and 35,400 horsepower of compression (Energy Pipeline News, 2001, 2004). The top of the salt is around 530 m below ground level (Halbouty, 1979) and the caverns have been used to store natural gas for over 30 years, operating in brine compensated mode (gas is injected/withdrawn as brine is removed/replaced).

On the 25th August 1974, liquefied butane gas was being pumped into the cavern with displaced brine moved to an open pond for storage. A miscalculation in the cavern volume amounting to 2190 tonnes (circa 10^6 US gallons), led to the cavern being overfilled, although the amount that eventually escaped is not known. As the gas replaced the brine in the well, pressure was lost, allowing high velocity escape of butane, which quickly formed a flammable cloud 2 kms (1.25 miles) in diameter (AEA, 2005).

Sometime after the release of butane, there was a small explosion and a fire, which caused convection and mixing of the cloud and air column. This led to a second explosion, some 240 m – 305 m above the ground, which damaged houses up to 275 m away and shattered windows up to 11 kms away (AEA, 2005). The fire burnt for 5 hours before the well was controlled by pumping brine into it and closing the valves. In all, 24 people were injured and around 3000 evacuated during the incident (Hirschberg et al., 1998; AEA, 2005).

West Hackberry, Louisiana (USA)

Located near Lake Charles in southern Louisiana, the West Hackberry salt dome (Fig. 25) was known as early as 1902. The top of the dome is at around 545 m below ground level (Halbouty, 1979). The salt deposits provided brine for the local chemical industry and in 1977, a number of the resulting caverns were acquired by the US Department of Energy (DOE) for the SPR. The first crude oil delivered to the SPR on July 21, 1977 was stored at the West Hackberry storage site, which now has 22 caverns capable of providing 219 mmbbl storage space.

On September 21st 1978, during work on one of the wells servicing the Number 6 cavity (it was serviced by more than one well in order to speed up operations), there was a sudden release of an estimated 72,000 bbl of oil, which caught fire, killing one of the crew. The oil geyser continued until the cavern had depressurised (Bérest & Brouard, 2003). A DOE report into the accident (1980) concluded that it arose as a result of work to repair a leak in the outer casing of the well completion and to reinforce wellhead equipment. This involved the withdrawal of an inner pipe and installation of a packer to seal off the cavern. During the work, however, the packer moved and was then pushed to the surface by the pressure of the oil. This led to the sudden and violent release of the cavern contents. The release and the associated oil geyser, continued until the pressure reached zero.

The investigation and safety reports concluded that any future work of this nature should be done when cavern pressures are lower and the wellhead pressure is zero. The incident serves to illustrate that the highest risks at cavern storage facilities result from special activities, rather than during normal operations (Bérest & Brouard, 2003).

Mont Belvieu (aka Barbers Hill), Chambers County, Texas (USA)

The Mont Belvieu gas storage facility is closely linked to the Barbers Hill oilfield discovered in April 1916 and developed in association with a salt dome near Mont Belvieu, approximately 48 kms northeast of Houston (Fig. 25). The salt dome has served as an underground storage facility in more recent years, with around 150 solution-mined caverns constructed to store liquid propane gas for the area's numerous refineries.

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The salt dome has a diameter of approximately 1600 m (1 mile), arising from mobilisation of the Jurassic Louann Salt at depth. It has led to an oval-shaped area up to 14 metres above the surrounding land level and caused radial faulting of the rocks pierced by the salt dome (Fig. 33). In 1955 Warren Petroleum Company commenced construction of underground storage caverns and a gas terminal. Twenty-six caverns with a capacity of 43 mmbbls of LPG (a mix of propane and ethane) were built making it the largest such facility for LPG in North America. Today, many other companies operate similar facilities in the area. Up to 150 active solution-mined caverns now store between 75 and 300 mmbbls of hydrocarbon products, making this, the world's largest storage site for petrochemicals and volatile hydrocarbons.

On September 17th 1980, a drop in pressure was recorded in one of the cavities holding the LPG, due to an underground leak in which the LPG gasified. It is believed that almost 28.3 Mcm (1 billion cubic feet) of an ethane-propane mix was lost from one of the caverns (Pirkle, 1986; Bérest et al., 2001). The cause of the initial leak was traced to a hole in the corroded casing of a well, dating from 1958, within the caprock overlying the salt at a depth of around 550 m (Pirkle, 1986; Bérest et al., 2001). The low-density propane and ethane rose through the cement outside the casing and then through porous rocks, faults and joints, accumulating in reservoirs at depths of 60 m – 120 m at pressures near the fracture pressure of the strata. Additionally, the gases migrated to the near surface and were found in a water-bearing sand 10 m thick beneath the town of Mt Belvieu. Relief wells were drilled into the high-pressure reservoirs at 60 m – 120 m and the gases flared off. The gas mixture migrated into the foundations of a house in the area and on October 3rd ignited when a spark from an electrical appliance (believed to be a dishwasher) triggered an explosion. In the days following, gas escapes appeared elsewhere, forcing 75 families from their homes for almost six months.

To relieve gas accumulations in the near surface, water-bearing sands, approximately 500 wells were drilled. In addition, the shallow sand was purged with nitrogen with shallow wells serving both as injection points and extraction points. As part of the post-incident remedial work and ongoing monitoring, over 100 monitor wells were installed on the operator's property. These wells have been regularly monitored both around each storage cavern and around the property perimeter to provide early detection of any similar product release.

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The 1980 explosion was followed by numerous other gas related incidents in the area over the years. In October 1984, several million dollars damage to property was caused after a further fire and explosion at the storage complex. This was followed by another explosion and fire in November 1985. On this occasion, two people were killed and the town's entire population of more than 2,000 residents were evacuated.

Prompted by these incidents, more than 200 homeowners and several churches within 240 m – 250 m of an underground storage well accepted buyouts as part of an eventual settlement with a nine-member industry consortium.

Other incidents related to the gas storage operations in the area include: an ethylene leak that closed Texas (route) 146 running through the town; a pipeline rupture that led to a gas leak and explosion in December 2000, which destroyed a home and released a large gas cloud 15 m into the air. There were reports the explosion caused several minor injuries, the evacuation of about 40 homes and the diversion of airplane flights around the area. There are also sketchy reports of explosions at two underground storage wells that burned for 43 days, and a major fire at Warren Petroleum Company when two workers were killed with many acres of land scorched.

Salt Dome Storage Field, Mississippi, USA

Sketchy reports exist of gas leakage at a salt dome storage facility in Mississippi in the early to mid 1980s (Pirkle, 1986; Pirkle & Jones, 2004), though the exact date and location is not known. The salt dome is likely to have been formed from the Louann Salt of Jurassic age.

A leak was suspected in one of the four storage caverns via a well. In order to identify the source of the leak, a grid of soil gas samples was taken from around the suspect storage well from

depths of circa 1 m for analysis of any hydrocarbons present. A clear hydrocarbon soil gas anomaly was observed largely within 3 m – 4.5 m of the well bore, with some annomalies up to 15 m away. Both the molecular and isotopic compositions of the anomalous surface soil gases were found to be identical to the composition of the stored product. The leak of the well resulted from poor cement jobs at the time of casing installation. The well was shut in and repairs undertaken (Pirkle, 1986; Pirkle & Jones, 2004).

Similar surveys around the other three storage wells were conducted. Two wells exhibited no evidence of hydrocarbon leakage, whilst around the third an area of approximately 38 m diameter was found where hydrocarbon concentrations in the soil gas at a depth of 1 – 1.5 m were 15% by volume. Again the molecular and isotopic composition of these soil gases was identical to the stored product. The leakage was attributed to poor cementation when the casing was installed. The operator immediately undertook remedial work, emptying the well and repairing the leak (Pirkle, 1986; Pirkle & Jones, 2004).

Mineola, Houston, East Texas

An incident, involving a blow-out and fire, occurred at an underground LPG (propane) salt dome storage facility operated by Suburban Propane near Mineola, East Texas, around 145 km east of Dallas (Fig. 25; Gebhardt et al., 1996; Bérest & Brouard, 2003; Warren, 2006). The exact date of the incident is slightly confused, with an incident in 1993 described on the WCO website (http://www.wildwell.com/Firefighting/ff_na4.htm) that makes reference to the novel use of coiled tubing in this well capping operation, as also referred to in Gebhardt et al. (1996). However, identical events and circumstances are described and attributed to the same authors (Gebhardt et al., 1996; Bérest & Brouard, 2003) relating to an incident in 1995 (Warren, 2006).

The facility utilised two salt caverns serviced by two wells, which were originally drilled as oil exploration and producing wells in the 1950s. Subsequently, the wells were used to inject water to leach the caverns after which they acted as the injection and withdrawal wells for the storage facility. The caverns, constructed in the Jurassic Louann Salt, extend from 360 m to 750 m below ground level (1200-2500 ft), with production string casing set at 483 m and tubing string to 732 m. Hydrostatic pressure at the bottom of the tubing string was 1,040 psi (Gebhardt et al., 1996).

Initially, it was thought that work on a storage well had caused fracturing of the salt, allowing communication between the two caverns. Further investigations revealed the incident had arisen because the storage facility was operated in brine compensation mode. This meant that new brine was introduced during each withdrawal of product, which had dissolved the salt, enlarging the caverns and narrowing of the salt wall between them until it was too thin to prevent the caverns from connecting. At the time of the incident there was circa 13 million gallons stored in one cavern, whilst the adjacent cavern was brine filled and undergoing a mechanical integrity test, involving cyclical injection and pressurisation with nitrogen. These operations and pressure variations caused failure of the salt wall, allowing the stored propane to flow into the adjacent cavern under test. This created a pressure build-up that ultimately caused a leak via the well casing that went undetected, allowing the stored propane to escape (Bérest & Brouard, 2003; Warren, 2006).

The propane migrated through the overburden via shallow sandy soil horizons reaching the surface in a halo extending up to 30 m from the well, where it found an ignition source. The fire burned with heavy black smoke. Around 15 m away from the product withdrawal, a water well that had been used during cavern leaching operations also ignited and burned during the incident. The water well provided a route to the surface for the propane that had collected in a shallow sand.

Extinction of the fire was not considered an option due to the likelihood of further unpredictable build-ups and re-ignition of the escaped propane. The situation was eventually brought under control using innovative kill techniques employing coiled tubing (Gebhardt et al., 1996).

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Brenham, Texas (USA)

The Brenham salt dome, known since around 1915, lies on the Washington-Austin county border in Texas (Fig. 25), with the top of the salt occurring at around 350 m below ground level (Halbouty, 1979). The Wesley storage facility near Brenham, Texas, is an unmanned 52 acre site that in 1992 was owned and operated remotely from Tulsa, Oklahoma by an affiliate of the Seminole Pipeline Company; MAPCO Natural Gas Liquids Inc. (MNGL). The site was subject to a major incident in April 1992.

The cavern at the centre of the incident is around 810 m below ground level with a height of at least 50 m (Bérest & Brouard, 2003). Caverns at this facility were storing LPG and being operated in brine compensation mode. The brine was stored in two above ground ponds and it was found there had been some enlargement of the cavern due to the use of undersaturated brine. Wellheads were equipped with shut-down valves. The National Transportation Safety Board investigated the incident (NTSB, 1993a) and found a sequence of events and failures of procedures that led to the release of product and a series of explosions and a fire. Early in the morning of April 7th, 1992 operations to inject LPG into a cavern commenced. Ultimately, these operations led to a blast that registered 4+ on the Richter Scale in Houston (Thoms & Gehle, 2000) and was heard 160 kms away and felt 258 kms away. The blast left 3 people dead, 23 others injured, destroyed 26 homes within 1.5 miles of the explosion and damaged a further 33 homes. The ensuing fire scorched an area of 0.74 km^2 (8 million square feet; NTSB, 1993a&b, 2006; Thoms & Gehle, 2000; Gruhn, 2003).

The NTSB investigation found that the explosion was caused when the storage cavern was overfilled with liquefied gas that pushed its way to the surface, pouring into an adjoining brine pit. Two valves in a brine sensing line were closed at the time of the accident, preventing sensors from detecting the increased pressure as the gas moved up the main pipeline. The valves had probably been shut during a maintenance review several weeks before the accident. No backup system was in place to allow for human error. Once above ground, the LPG vaporized rapidly and being heavier than air, formed a low-lying cloud several hundred metres long and 6 m – 9 m deep. A spark of unknown origin, but most likely from a passing car, triggered the explosion.

MNGL and the parent company (Seminole) were found to have failed to incorporate fail-safe features in the facility's wellhead safety system. The cause of the overfilling was the inadequacy of procedures for managing cavern storage. The company believed the cavern to be holding 288,000 barrels (circa 45,800 m^3) of liquid. However, the safety audit following the explosion suggested that the figure was nearer to 332,000 barrels (circa 52,500 m^3). The cavern was therefore filled beyond its capacity. Other contributory factors found were the lack of federal and state regulations governing the design and operation of underground storage systems and inadequate emergency response procedures.

Following the explosion, the LPG storage cavern passed a mechanical integrity test (Thoms & Gehle, 2000) and the operator applied to re-open the facility with an increased capacity. Almost two years after the blast, permission was refused and the Texas Railroad Commission, which regulates the oil and gas industry for the state, ordered that the facility be shut down permanently. The company fought the closure, losing several appeals and the site now operates as a pump station for pipelines. The cavern is empty.

A lawsuit brought by victims of the blast eventually resulted in a jury award of $5.4 million in compensatory damages and $138 million in punitive damages.

Stratton Ridge, Freeport, Texas (USA)

The Stratton Ridge salt dome in Brazoria County near Freeport, Texas (Fig. 25), was discovered in 1913. It represents a typical Gulf Coast salt dome (Applin, 1925), the top of which is at around 381 m (1250 ft) below ground level (Halbouty, 1979).

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Caverns in the salt dome have been used to store LPG/NGL's for many years (Halbouty, 1979). These include the caverns referred to as the Stratton Ridge Facilities, which in 2004 were owned by Dow Hydrocarbon & Resources, who were leasing them to Kinder Morgan Energy Partners L.P for gas storage purposes. The facility has a combined capacity of 334.1 Mcm of natural gas, working natural gas capacity of 153 Mcm and a peak day deliverability of up to 11.3 Mcm per day (http://www.kindermorgan.com/investor/kmp_2004_annual_report_financials.pdf).

In the early 1990s, a salt cavern was commissioned as a natural gas storage facility at the Stratton Ridge salt dome. However, the cavern had to be abandoned when, during testing, it failed a mechanical integrity test, having leaked gas whilst being pressured up for storage (Hopper, 2004).

Magnolia, Grand Bayou, south Louisiana (USA)

The Magnolia salt dome is located in a sparsely populated area at Napoleonville, about two miles from Grand Bayou, south Louisiana (Fig. 25). In 2003, a cavern gas storage facility was constructed in the dome, operated by Entergy Koch/Gulf South (http://www.txgt.com/sec/Pipelines%2010K%2012-31-05%20FINAL.pdf; Hopper, 2004). On Christmas Eve/Day 2003, only six weeks after operations began at the facility, around 30 people were forced from their homes by a natural gas leak that led to the release of about 9.9 Mcm of gas in a matter of hours.

Investigations revealed that the gas escaped from a crack in the casing of a well near the top of a cavern, some 440 m (1,450 ft) below the surface. It was eventually plugged at a point below the crack and four other wells were drilled in the area to monitor and control the release of leaked gas that was bubbling up from underground.

Moss Bluff, Texas (USA)

The Moss Bluff salt dome, located in Liberty County about 64 km (40 miles) northeast of Houston Texas (Fig. 25), was known as long ago as 1926 (Halbouty, 1979). It is a typical Gulf coast salt dome with the development of a rim syncline. The top of the salt lies at around 330 m below ground level and the base at depths greater than 3 km (Fig. 34).

The development of the salt dome has led to the region being dotted with man-made caverns and represents one of the world's largest storage sites for hydrocarbons. The Moss Bluff gas storage facility, comprising three separate underground caverns in a 640-acre site, is operated by Duke Energy Gas Transmission and represents an important component in the regional production, storage and shipping of natural gas. An onsite compressor station pumps natural gas into and out of the caverns through wellhead assemblies on each of the caverns. There are related facilities for the transport and/or storage of hydrocarbons and pipework for natural gas, freshwater and salt water (brine). The operation of the caverns is brine compensated (brine is withdrawn from the cavern as gas is injected).

In August 2004, an incident occurred at cavern nos.1, the top of which is approximately 760 m below ground level and is circa 427 m high. For several days prior to the incident, cavern number 1 was operating in "de-brining mode" when brine was being brought to the surface and pumped to a surface holding pond (Duke Energy, 2004;http://www.solutionmining.org/cmsFiles/Files/MossBluff_Part1ExecSum_&_IncidentDescrp.pdf). At the same time compressed gas was being injected into the cavern. Monitoring of brine-gas levels before the incident indicated that the brine/gas interface at the time was at 1132 m, some way from the bottom of the well string.

At just after 4 am on 19th August 2004, a leak in a pipe led to a sudden gas release from cavern Nos.1. The resultant explosion and fire caused the closure of roads and forced dozens of residents from their homes within a 1.6 km (c. 1 mile) radius, although no one was reported injured. A valve that could possibly have been used to turn off the flow of gas was inaccessible due to the heat of the fire. It was reported 1 person was present inside the facility at the time of the blast and was able to escape. A second explosion occurred the following day and the

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evacuation zone was expanded to 4.8 km (c. 3 miles), with local press reports suggesting the total number evacuated to be around 360. The fire remained above ground throughout the incident and for safety reasons was allowed to burn itself out. It was eventually extinguished 6½ days later at 9:15 p.m. on August 25th, when a blowout prevention valve was successful installed. During this incident, the safety and integrity of the two other storage chambers at the facility was never threatened.

Detailed investigations by Duke Energy and consultants subsequently revealed a series of events responsible for the uncontrolled gas release and resultant fire (Duke Energy, 2004; http://www.solutionmining.org/cmsFiles/Files/MossBluff_Part1ExecSum_&_IncidentDescrp.pdf). There was an initial separation and breach of the 8 5/8-inch well string inside the cavern at, or above, the 1135 m level. The reason for this breach remains unknown, as the affected materials could not be recovered from the cavern. However, records indicated that, only 10 days prior to the incident, the well string showed no signs of a separation. The breach permitted high pressure gas to displace the brine in the well, enter the well string, reach the surface and flow into the 8-inch above ground brine pipework. The emergency shutdown (ESD) system in place on the 8-inch brine pipework, a short distance from the wellhead assembly was designed to close on the detection of a change in pressure, flow and/or composition. The ESD operated properly. However, the sudden surge of flow acted like a "water hammer" and caused the 8-inch pipework between the wellhead and the ESD valve to rupture. This failure occurred at a location in the pipework that had suffered a general loss of wall thickness due to internal corrosion. The extent of the internal corrosion of the brine pipework was not anticipated due to the relatively short period of time it had been in service (installed and tested in 2000). The incident was prolonged when the extreme heat of the fire blew off the entire wellhead assembly early on Friday, 20th August. For about 28 seconds the fire appeared to have been extinguished, but gas escaping through the 20-inch production casing re-ignited and burned until it was extinguished finally on the 25th August.

The investigations concluded that the operating procedures were adequate and followed appropriately. Valve positions were confirmed and found to be correct. A thorough review of operator logs and employee interviews revealed no evidence for procedural or human error that contributed to the incident.

Odessa, Texas, USA

Natural gas liquids are stored underground in caverns at the Huntsman Polymer site in Odessa, Texas. Although not finally confirmed, this is likely to be in salt caverns engineered in one of the many salt domes in the Texas area. According to a single report, more than 100t of natural gas liquids escaped on 16 March 2004, due to a faulty gasket. The remaining gas was flared off, with no injuries reported (Hazardous Cargo Bulletin, June 2004).

American incidents involving storage facilities constructed in Permian salts

Salt deposits of Permian age are found across central America and have long been used for brine extraction and the construction of cavern storage facilities. More than 600 solution mined salt caverns exist in Kansas alone, many of which are used for the storage of natural gas liquids (NGL's) and refined liquid products. In Kansas, the salts form the Hutchinson Salt Member of the Wellington Formation, separating the Lower and Upper Wellington shales (refer Figs 25&35). The Hutchinson Salt Member can be up to 215 m thick and in general, occurs as a series of distinct salt beds with interbedded mudstones and anhydrites. The Permian Ninnescah Shale between 61 m and 84 m thick conformably overlies the Wellington Formation. Permian strata are overlain by the unconsolidated Equus Beds of Pleistocene age up to 100 m thick, which form the local freshwater aquifer for much of south-central Kansas.

Leakage of stored product is reported from two cavern storage facilities developed in the Hutchinson Salt Member in Kansas.

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Conway Underground East facility, Conway, McPherson County, Kansas (USA)

The Conway area in McPherson County, Kansas, has around 300 active and plugged & abandoned storage caverns. Some have been used for storage since 1951, when the National Cooperative Refinery Association commenced operations west of the town of McPherson. Other storage fields were developed around the town of Conway during the 1950's, 1960's and 1970's (Ratigan et al., 2002).

The Hutchinson Salt Member in the Conway district dips westwards and is typically 61 – 183 m (200 – 600 ft) thick. To the east dissolution of the salt has occurred and resulted in a zone of wet rock head, with collapse breccia formed from the overlying Upper Wellington Shale. Across this zone of wet rockhead, wells encounter a loss of circulation at the top of the salt, indicating voids and in which hydrocarbons have been recorded as recently as December 2000 (Ratigan et al., 2002). The overlying Ninnescah Shale is between 61 m and 84 m thick. The unconsolidated Pleistocene deposits (Equus Beds) do not, however, extend beneath the Conway Underground East facility; the western edge of the aquifer lies circa 1 km to the east of the site.

Records show that natural gas liquids (NGL's) and gas has been escaping from cavern facilities in the Conway area since 1956 (Ratigan et al., 2002). NGL's and gas have been encountered in both storage wells and domestic wells in and around Conway itself on at least six separate occasions between 1980 and 1981. The leaks and presence of propane and hydrocarbons in local groundwater led to several storage operators purchasing around 30 homes and relocating the occupants. At the time, Kansas Department of Health and Environment also required investigations to discover the origin of the leaking propane gas.

One of the most recent incidents occurred at the Williams Midstream Natural Gas Liquids' Conway Underground East Storage facility. Storage of jet fuel for a nearby air force base began at the site in 1959, with extension of the facility in 1974 when operated by Home Petroleum. Williams acquired the facility in 1987 and in December 2000, NGL's were encountered in a newly drilled well at the site. Investigations into their presence indicated that large areas of the storage facility, particularly the north-central part, lie in the area affected by salt dissolution (wet rockhead). Up to 10 m of the upper salt bed is now missing, with collapse breccias forming voids into which hydrocarbons have migrated (Ratigan et al., 2002). Further occurrences of NGL's have been encountered in two shallow groundwater monitoring wells and investigations during 2002-2003, that included soil gas sampling, were ongoing to assess how and by what route the NGL's and gas present in the area of wet rockhead could migrate upwards into the local aquifer. The results have yet to be made widely available.

Hutchinson – aka Yaggy, Kansas (USA)

The town of Hutchinson, with a population of around 44,000, lies around 11 km (7 miles) SE of the Yaggy Storage Field (Figs. 25&35), and provides the location for perhaps the most publicised and notorious UGS incident. The area is underlain by the Hutchinson Salt Member, which has been mined and extracted at Hutchinson since the 1880s and in which caverns had been created for storage purposes. At the time of the incident, the Yaggy storage facility played a key role in the supply of gas in central Kansas and was thus of national importance. It was one of 30 "hubs" in the USA national gas distribution system and one of 27 such cavern storage fields in the USA. The incident has been extensively reviewed elsewhere and so will only be outlined here, with emphasis on the history of the facility to illustrate the background to the disaster.

The Yaggy field was originally developed in the early 1980s to hold propane. The storage caverns were formed by salt dissolution using brine wells, drilled to depths between 152 m and 274 m in the lower parts of the Lower Permian Hutchinson Salt Member of the Wellington Formation (Fig. 35). The top of each cavern was located about 12 m below the top of the salt layer to ensure an adequate caprock that would not fracture or leak and the wells were lined with steel casing into the salt. The Wellington Shale Formation is overlain by the Ninnescah Shale, both of which dip to the west and northwest and form the bedrock to 15 m or more of the sands

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and gravels of the Equus Beds. These unconsolidated deposits underlie (Fig. 35) and provide the municipal water supply for the city of Hutchinson, and the city of Wichita to the east.

Decreasing financial viability eventually led to the closure of the propane storage operations in the late 1980s. The wells were cased into the salt and later plugged by partially filling them with concrete. In the early 1990's, Kansas Gas Service, a subsidiary of ONEOK of Tulsa (Oklahoma), acquired the facility and converted it to natural gas storage. The existing caverns were re-commissioned, which required drilling out the old plugged wells, whilst further wells were drilled to solution mine additional caverns.

Mention is made of the Yaggy Storage Field consisting of 98 caverns in the Hutchinson Salt Member at depths greater than 150 m. It appears that at the time of the 2001 incident, the facility had about 70 wells, of which 62 were active gas storage caverns, at depths greater than 152 m. More than 20 new wells had been drilled and were being used to create new caverns for expansion of the facility (Allison, 2001a). The wells, with 90-120 m spacing, are located on a grid. A group of wells are connected at the surface via pipes and manifolds, allowing gas to be injected or withdrawn into all the caverns in the group simultaneously. The capacity of the Yaggy field was circa 90.6 Mcm (c. 3.2 Bcf) of natural gas at around 600 psi.

The incident at Hutchinson occurred on the morning of January 17th, 2001, when monitoring equipment registered a pressure drop in well S-1, which connected to a cavern being filled. The cavern could hold 1.7 Mcm of gas at an operating pressure of about 4.65 MPa (675 psi). This could, however, range from 3.8 to 4.7 MPa (550 to 684 psi). Later that morning a gas explosion occurred in downtown Hutchinson, around 11 km (7 miles) away and was followed by a series of gas and brine geysers, up to 9 m high, erupting about 3.2 km (2 miles = c. 9 miles from the storage site) to the east along the outskirts of Hutchinson (Fig. 35). The following day (18th January), a gas explosion at the Big Chief Mobile Home Park killed 2 and injured another (Fig. 35). The city promptly ordered the evacuation of hundreds of premises: many not returning to their homes and businesses until the end of March 2001.

An investigation into the incident led by the Kansas Geological Survey (e.g. Allison, 2001a&b), found the leak was the result of a large curved slice in the casing of the S-1 well at a depth of 181.4 m, just below the top of the salt and 56 m above the top of the salt cavern. The damage to the casing resulted from the re-drilling of the old cemented well when re-opening the former propane salt cavern storage facility. Furthermore, ONEOK computer operators in Tulsa had overloaded the storage field caverns with natural gas, causing the initial leak. For at least 3 days the casing leak allowed natural gas at high pressure to escape and migrate upwards through the well cement and fractures in rocks above the salt. On reaching a permeable zone formed by a thin bed of micro-fractured dolomite near the contact between the Wellington Formation and the overlying Ninnescah Shale at around 128 m, the gas was trapped by overlying gypsum beds, preventing further vertical movement. The dolomite was fractured in the crest of a low-amplitude, asymmetric, northwesterly plunging anticlinal structure and the pressure of the escaping gas induced parting along the pre-existing fracture system. The gas migrated laterally southeastwards up-dip along the crest of the anticline towards Hutchinson, where it ultimately encountered old abandoned and forgotten brinewells that provided pathways to the surface (Allison, 2001a; Nissen et al., 2003 & 2004).

Geological investigations of the area suggest that the fractures in the dolomites were related to deep seated fractures that caused faulting in the overlying strata. These fractures then appear to have permitted undersaturated water to penetrate down and dissolve the Hutchinson salt, causing variations in thickness of the halite beds. Faulting in strata overlying the halite beds is greatest where dissolution has taken place and the edge of this dissolution zone trends NW close to the crest of the anticlinal structure. The dissolution of the halite appears to have locally enhanced structural relief, which led to further stresses, fracturing and preferred zones of weakness in the overburden, providing pathways for gas migration along the trend of the anticline (Watney et al.,

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(Cont.)

2003a; Nissen et al., 2004b). Shut in tests on vent and relief wells following the incident revealed that with reduced gas pressures, fracture apertures were reduced and closed as pore pressures declined.

Basic volumetrics of the fracture cluster were calculated (Watney et al., 2003b):

- Length – 14 km (8 miles)
- Width – 300 m (1000 ft)
- Height – 0.9 m (3 ft)
- Porosity – 2%
- Fracture volume – 78,000 m^3 (2.8 Mcf)
- Estimated volume of gas released – 4.04 Mscm (143 Mscf) = 99,109 m^3 (3.5 Mcf) at 4.14 MPa (600 psi), 12°C (54°F)

Other storage facilities exist around Hutchinson and provide some useful information on storage pressure gradients. In late 1996 to 1997, Western Resources Inc. who operated a hydrocarbon storage well facility to the west of Hutchinson, submitted requests to the Kansas Department of Health and Environment (KDHE) to increase the maximum storage pressure gradient at their facility. KDHE regulate gas storage operations and operated a 'rule of thumb' that the maximum storage pressure gradient at such facilities in the Hutchinson area was limited to 0.75 psi/foot of depth. This was in order to prevent fracturing of the salt deposit. Following tests on rock cores, Western Resources Inc. requested increasing the pressure from 0.75 psi/foot of depth to a pressure gradient of 0.88 psi/foot of depth, which was actually close to the average fracture pressure gradient of 0.89 psi/foot of depth. One rock sample actually had a fracture pressure gradient of 0.72 psi.foot of depth (KDHE, 1997).

The original downtown explosion site was related to a mineral water well in a basement that had provided mineralized waters for a hotel spa. The second explosion occurred at the site of an old abandoned brinewell. Images of a blazing well in the ruins of a building are available on the Kansas Geological Survey website (http://www.kgs.ku.edu/Hydro/Hutch/CUDD/2nd/set01.html). The same was found to be true for the numerous gas and brine geysers to the east of the city and the explosion at the Big Chief trailer park. When drilled, most old brine wells were only cased down through the shallow Quaternary "Equus beds" aquifer. The deeper parts of the wells were open-hole and thus provided ready pathways for the gas to escape to the surface. As many as 160 old brinewells are thought to exist in the Hutchinson area, either buried purposely or by subsequent development. It is unlikely that the well casings of these wells, if they exist, are sufficiently gas tight to prevent gas escapes and would present problems if future leaks were to occur.

Following the operations to trace and deal with the January leak incident, a second event occurred around six months later on the afternoon of Sunday, July 7, when one of the vent wells (Deep Drilled Vent well 64) suddenly started venting gas at high pressure (Allison, 2001c). The following day, the flare was reported at about 4 m in height and a pressure of 2.3 MPa (330 psi). Mechanical modifications to the surface pipework were made with the result that the flare reached an estimated 9 m - 30 to 12 m in height by Monday evening. Pressures had dropped to only 0.04 MPa (6 psi) by the following Wednesday; when the well was temporarily shut in. However, the pressures then increased quickly again.

Three possible causes for the flare-up were identified (Allison, 2001c):

- formation or near-well-bore damage – this is caused by the flow of water and gas through the near-well-bore environment. The permeability of the rock near to the well is reduced by the plugging the rock with fine materials, chemical alteration, or by changes in relative permeability as the volume of gas drops relative to the volume of water. Such "damage" routinely occur in oil and gasfield wells and is readily corrected.

D2-253 (Cont.)

- segmented pockets or fractures of gas remained - when the gas first entered Hutchinson it was under sufficiently high pressure that it may have forced open previously closed fractures in the rock layers or pushed its way into areas of 'tight rocks', i.e. less permeable rocks. As pressures dropped, it is possible that some fractures would have closed up again, isolating small amounts of gas in separate pockets, which over time, could have worked their way back into the main accumulation and into the vent well.
- another source of gas besides the Yaggy field exists – a scenario thought to be unlikely as well DDV 64 sits in the midst of a swarm of vent wells and it is hard to project a new source of gas that would affect only this one well.

The causes of the resurgence of gas were still being investigated in late 2001/early 2002. However, the results of this investigation, although it is likely that they have been published, have not been found during this study.

The incident in 2001 was not the first time that there had been problems with a cavern and well at the Hutchinson storage facility. On September 14, 1998, a shale shelf collapsed inside the field's K-6 cavern, trapping a gamma-ray neutron instrument that had been used for monitoring purposes. Downhole video surveys revealed the casing on the verge of collapse at about 183 m, with the camera unable to go below 205 m, due to the blockage. In October 1998, a plan was established to remove gas from the cavern over the winter. In the spring of 1999, the radioactive tool was buried under 1.2 m of concrete and the cavern's main pipe was relined with bonding cement to block any possible leaks. The cavern is still monitored for radiation leaks.

Elk City Oklahoma, USA

Brief mention is made of an apparent incident at a salt cavern storage site in Oklahoma (Katz, 1974). If it proves to have some foundation, then it is likely to have been at a facility developed in Permian salts, which extend across Oklahoma and into Kansas, in the same basin as those salts found at Hutchinson. At the time, the incident was reported in the Elk City newspaper with mention of 30 ton boulders being thrown in the air and landing in a field. Katz (1974) concluded this "is the kind of event to be avoided." No other details are readily available.

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Salt Block Storage Well, Goodyear, Arizona, USA

Again, sketchy reports exist for gas leakage at a salt cavern storage facility in Arizona (Pirkle, 1986; Microseeps), though the exact date and location and depth of storage is not known. The salts are likely to have been Permian in age.

Propane was stored in salt caverns in an area of salt referred to as the Luke Salt near Goodyear, Arizona. At some point in the storage operations, the well casing in one of these caverns developed a corrosion hole and lost 'several million cubic feet' (perhaps 0.5 to 0.85 Mcm) of propane into the surrounding and overlying strata at a depth of a few hundred metres. The propane accumulated in strata just above the water table at a depth of approximately 92 m and was found in several open water wells in the area.

Three relief wells were sunk to the top of the water table to remove the propane from the formation, with the rate of escape to the atmosphere found to be influenced by daily fluctuations of barometric pressure (Pirkle, 1986; Microseeps).

Canadian cavern storage incident

Fort Saskatchewan, Alberta

As previously alluded to, the Saskatchewan Power Corporation constructed the first salt cavern designed specifically for the storage of natural gas at Melville, Saskatchewan, Canada. It was constructed in the Mid Devonian Prairie Evaporite salt formation at a depth of circa 1128 m (3,700 feet) with a capacity of 290,000 bbl, and came into service during 1963.

Fort Saskatchewan, Alberta lies in the Interior Plains area of Canada, in the Western Canada sedimentary basin (Fig. 25). Within the basin clastics, redbeds, carbonates and important salt and potash deposits of Lower to Middle Devonian age were deposited unconformably upon Precambrian or lower Palaeozoic rocks (Meijer Drees, 1994; Hamilton & Olsen, 1994). These sediments form the Elk Point Group and accumulated in topographic basins, separated by highlands, some areas of which remained emergent until late Middle Devonian times.

The salt beds form two distinct types and define the Upper and Lower subdivisions of the Elk Point Group. The Upper Elk Point contains the Prairie Evaporite salt formation, being up to 200 m thick and by far the most extensive deposit (Fig. 36). It does, however, vary in purity within the basin. Salt also occurs as three separate and very pure deposits within the Lower Elk Point: the Lower Lotsberg, Upper Lotsberg and Cold Lake salt formations. These salts are more restricted in area but can also attain considerable thickness.

In 2001 BP Canada Energy Company were operating a natural gas liquids (NGL) plant located about 6 kilometres northeast of the City of Fort Saskatchewan, near Edmonton, Alberta. NGL products have many uses in the petrochemical industry and were being stored on site in underground caverns and delivered through pipelines to a number of locations in Alberta, eastern Canada, and the United States. The facility represents an important part of the Alberta NGL pipeline network.

An incident occurred between August 26th and September 3rd, 2001, when fire broke out at one of the ethane wells (Fig. 36), connecting to Cavern 103. The cavern was constructed in the Lotsberg Salt Formation at a depth of about 1850 m and had been used to store NGL's for 25 years. Cavern capacity was circa 0.127 Mcm and at the time of the incident, there were approximately 0.076 Mcm of ethane in the cavern.

Fires and black smoke were visible up to 50 kms away, but the incident was contained entirely within the plant site and although it caused breathing difficulties for some locals, was said to have presented no danger to the public. An investigation by the Alberta Energy and Utilities Board (EUB, 2002) found that early on August 26th 2001, ethane was being pumped up well 103 by displacing the ethane in the storage cavern with brine injected into the cavern via well 103A. Just after 7:00 am the cavern 103 gas detector relayed an alarm to the main control room at the Fort Saskatchewan site, with a vapour cloud observed in the area above cavern 103 facilities. Cavern 103 was shut in, with well 103 opened to a pipeline to reduce the ethane leak. However, this action failed to reduce the release rate.

The flames spread to the second well and the fire burned for over a week. This was largely for safety reasons, to allow the pressure in the gas cavern to reduce. By August 28th, heavy black smoke from the well fires was significantly less due to a combination of the ongoing fire control efforts and the reduced gas flow as the ethane storage cavern depressurised. On August 29, it was possible to close a connecting valve between the two wellheads, greatly limiting the fire at the both wells.

Investigations found that the leak had occurred due to failure on the exterior surface of the forged elbow on the line connecting the two wellheads. The growing ethane vapour cloud ignited sometime after 9 am, was ignited when it came into contact with overhead power lines located within the site. An explosion and fire ensued. The site was evacuated with no injuries to plant or emergency service personnel. In total, it is estimated that about 14,500 m^3 of ethane product was lost during the 8 days of the incident. In the weeks immediately afterwards, most of the plant and pipeline operations returned to normal, except for those involving the wells, pipelines, and the ethane storage cavern associated with the incident.

The magnitude of the change in operating pressure of cavern 103 and the speed of the pressure change that occurred may have caused damage to the cavern, with indications that cavern 103

D2-253 (Cont.)

now shows some signs of communication with an adjacent cavern. The ethane storage cavern 103 remains out of operation and will do so until the EUB grant approval to resume operations.

Salt cavern construction 'problems'.

A number of proposed storage facilities have developed difficulties during development and prior to completion. These are briefly reviewed in the context of potential problems that might be faced when developing storage facilities in the UK.

Cavern 7, Bayou Choctaw, Baton Rouge, Louisianna

In 1954, during operations to develop a cavern for storage in the salt dome at Bayou Choctaw, uncontrolled leaching operations led to the collapse of overburden into the developing cavern number 7 (Coates et al., 1981; Neal & Magorian, 1997). A 245 m diameter lake formed and a further cavern (number 4) continues to be monitored following the incident due to fears of collapse due to possible faults in the cap rock (Neal & Magorian, 1997).

Napoleanville and Clovelly

Problems have arisen in caverns constructed too close to the edges of the Napoleanville and Clovelly salt domes in southern Louisiana and have resulted in cavern integrity and pressure maintenance problems. This has meant that a number of caverns could not be commissioned (Neal & Magorian, 1997).

At Clovelly, cavern leaching in the salt overhang meant there was not a sufficient thickness of salt to act as a barrier (Fig. 37). At Napoleanville, shale layers were encountered in some caverns, indicating the salt dome edge and enclosing rocks had been encountered, with insufficient buffer salt remaining (Neal & Magorian, 1997).

Both incidents point to inadequate site characterisation prior to commencing development and brining operations.

D2-253 (Cont.)

Aquifer gas storage incidents - Europe

Spandau, western suburb of Berlin

Gas is stored approximately 800 m underground in an aquifer facility beneath the western suburbs of Berlin at Spandau (Fig. 30). Up to 6 Mcm of gas can be stored, enough to supply all Berlin households for a year.

At about 9.40-9.45 am on April 23rd 2004, a gas explosion occurred at one of the GASAG Gasspeicher Berlin well sites (Associated Press, 2004; Berliner Zeitung, 2004a,b&c). The incident appears to have occurred at a station where gas is pumped from underground storage to what are understood to have been road tankers. The explosion destroyed the wellhead of a monitoring(?) well and gas escaped and ignited, resulting in a flame about 30 m in height. The gas escaped for about a day before the well was successfully capped. Associated Press (April 23rd, 2004) reported that the incident injured nine workers, three seriously, destroyed a tanker and caused damage to several buildings, forcing the evacuation of around 500 residents in a 1 km radius (F. May, pers. comm., 2004; Associated Press, April 23rd, 2004). Indications are that the explosion occurred either as a result of maintenance work following winter operations (involving H_2O_2 treatment of the well - F. May, pers. comm., 2004), a defective seal, or work on the store's contents gauges, which began to leak. In any case, the incident appears to have resulted from the failure of above ground infrastructure and at no time was the stored gas inventory in danger (GASAG's web site, 2004: http://www.gasag.de/de/privatkunden/index.html).

Stenlille, Denmark

An underground gas storage facility in an aquifer was established in 1989 at Stenlille, approximately 70 km SW of Copenhagen in Denmark and operated by the state-owned Danish Oil and Gas Company (DONG; Laier & Øbro, 2004 & in press). In that area, salt movements in the Zechstein deposits have caused gentle doming of the overlying Late Triassic Gassum Sandstone Formation some 1500 m below ground. The clay-dominated Lower Jurassic Fjerritslev Formation forms a cap rock some 300 m thick. Natural gas is injected into the Gassum Sandstone Formation with the structure having an estimated capacity of 3 Bcm.

A minor gas escape occurred during one drilling operation in 1995. Gas bubbles were observed at the surface at the drilling site and an increase in gas concentration was found in the Palaeocene aquifer 130 m below ground (Laier & Øbro, 2004 & in press). No increases in gas concentration were detected in shallower level aquifers. The gas escape was due to a hole in the casing and was quickly remedied, with methane levels in the Palaeocene aquifer declining significantly since. Pressure and groundwater monitoring measures have detected no gas leakage from the underground storage site during normal operation.

Chémery, France

France, in addition to salt cavern gas storage facilities, has a number of aquifer storage facilities including that at Chémery, 120 miles SW of Paris (Fig. 21). Operated by Gaz de France, it is one of the largest in Europe and was commissioned in 1968. It stores gas piped in from the North Sea at depths greater than 1120 m (GDF, 1996). At the time of the incident, the aquifer storage facility had a capacity of around 6.8 billion cubic metres (Bcm) of gas at 130 bar (13 MPa/1886 psi).

On the 25th September 1989, a leak began during routine maintenance of a well completion and replacement of a filter at a depth of around 1106 m (3630 ft). Gas escaping at a rate of 0.15 Mcm/hr (5.2 million cubic ft per hour), the noise of which exceeded 120 decibels, led to the development of a gas cloud that rose around 7600 m (25,000 ft) into the air and caused the diversion of aircraft from a nearby airport (NAWPC, 1999; IAVWOPSG, 2005).

During the gas leak, power lines were shut down and no explosion occurred. A safety zone was established and the public kept informed of developments. The leak was finally plugged on the 27th September (IAVWOPSG, 2005). The incident was reviewed and guidelines drawn up for future maintenance procedures.

Frankenthal, West Germany

In the late 1970s and early 1980s, Saar-Ferngas operated an underground natural gas storage facility at Frankenthal, West Germany (Fig. 30). Reports of an incident involving the escape of gas from the facility are vague, with reference to large underground tanks and 'underground chambers in soft rock and sand layers' (AEA, 2005). That said it appears that some 16 Mcm of natural gas was being stored at a depth of around 680 m and 70 bar (7 MPa/1015 psi), in what is in fact an aquifer storage facility.

The incident was triggered on 30th September 1980 when drilling operations, close by the facility, encountered gas that immediately started to escape. Water and mud were pumped into the well in an attempt to stop the escaping gas but proved unsuccessful. The leak was eventually halted when a 14 tonne valve was fitted to an underground pipe, with the incident finally being brought under control on the 16th October. Indications are that the drilling activities had damaged an existing pipe to the underground 'storage chamber'.

Fortunately, the escaping gas never caught fire, but the value of the gas losses at the time were estimated at 10 m DM or 5 million dollars (AEA, 2005).

Ketzin, Berlin, Germany

The Ketzin gas storage facility is a former gas storage site around 25 km west of Berlin operated by UGS Mittenwalde (Fig. 30; Juhlin et al., 2007). It is developed in the Northeast German

D2-253 (Cont.)

Basin, part of a Permian basin system that extends from the east of England and the North Sea across Denmark, the Netherlands and northern Germany to Poland (Ziegler, 1990). As in the Southern North Sea, thick sequences of Zechstein salt were deposited, following which a thick series of sandstones and mudstones were deposited during Triassic and Jurassic times. Salt flowage has resulted in a series of pillows, walls and diapers, resulting in deformation of the overlying Mesozoic overburden that has formed a system of anticlines and synclines (Kossow, et al., 2000; Förster et al., 2006; Juhlin et al., 2007).

The Ketzin site lies on the eastern part of a double anticline, the Roskow-Ketzin Anticline (Juhlin et al, 2007), which is formed above an elongated NNE-SSW trending salt pillow developed at a depth of 1500-2000 m. The anticline developed during several phases of salt movement and (Juhlin et al., 2007). Lower Cretaceous rocks were eroded from the crestal regions at around 106 Ma.

Saline aquifers of Lower Jurassic age at between 250 and 400 m below ground are present in the Ketzin anticline and were used for storage of first town gas in the 1960s and between the 1970s and 2000, for natural gas (Juhlin et al., 2007). The operator (UGS Mittenwalde) suggests that the maximum utilization of the facility was n 1999. In 2004, the site was abandoned and the (aquifer) resevoir pressure was lowered to approximately 17 bar below hydrostatic pressure (Juhlin et al., 2007). Faulting affects the crest of the anticlinal structure, with a 600-800 m wide E-W striking central graben fault zone (CGFZ) in the crestal region. Faulting in the CGFZ extends down to Triassic levels and the bounding faults have about 30 m of downthrow, but faulting appears to die out quickly in the overlying Rupelian clays of Cainozoic (Tertiary) age (Juhlin et al., 2007). Although the facility has closed, some infrastructure from the facility still remains and deeper aquifers in the lithologicaly heterogeneous Stuttgart Formation of Upper Triassic age are being considered for CO_2 storage purposes (refer Juhlin et al., 2007).

Reports suggest that during the 1960s, the injected and stored town gas migrated out of the reservoir and ultimately found its way to the surface, causing the (permanent) evacuation of the nearby village of Knoblauch (New Energy News, 2007; MyDeltaQuest). There is mention that leakage of carbon monoxide (CO) was also associated with the leak (MyDeltaQuest). It would appear that during this incident, 1 person was killed when CO came up an old well into a house, following which the well was repaired and sealed (N.J. Riley pers comm., 2007). As mentioned above, gas storage continued until 2000 (Juhlin et al., 2007). Recent seismic reflection studies reveal amplitude anomalies in the aquifer units on seismic reflection data, indicating that remnant (cushion or residual) gas remains in some aquifer units near the crest of the structure. Amplitude anomalies and a gas chimney about 1 km long and 100 m wide has been observed on seismic reflection data acquired over the southwestern, east-west striking main fault of the CGFZ. This indicates that the stored or remnant gas either has been or is presently migrating out of the reservoir formations (Juhlin et al., 2007).

Aquifer gas storage incidents - America

Leroy Storage Facility, Uinta County, Wyoming, USA

The Leroy gas storage field is located in Uinta County, Wyoming, approximately 100 miles NE of Salt Lake City and in the period 1973-mid 1980s, was operated by Mountain Fuel Supply Company (Araktingi et al., 1984; Nelson et al., 2005). Early hydrocarbon exploration had defined an anticlinal structure (Fig. 38) bounded on its western side by a fault (Araktingi, et al., 1984). An exploration well, drilled in 1951 (Leroy #3), proved two potential coarse-grained sandstone reservoir units in the Triassic lower Thaynes Formation at a depth of roughly 900 m below ground level (circa 1161 m above sea level). These sandstones were re-examined for gas storage purposes in 1969. Shales, siltstones and anhydrite in the middle Thaynes Formation provided the cap rock for the storage reservoir (Araktingi et al., 1984; Nelson et al., 2005). The initial sandstone aquifer pressure was 1500 psig (103 bar/10.3 Mpa) and testing of the structure commenced in October 1970.

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Further appraisal continued with the injection of around 56.6 Mcm of gas during August 1972. Approval for the facility followed in November 1972, with further wells completed in 1973, increasing capacity to around 99.1 Mcm. However, on reaching 104 Mcm and a reservoir pressure of 1740 psia (120 bar/12 Mpa), gas began escaping from around the surface casing of well number 3.

Investigations revealed that the gas leakage originated from a corroded well casing in the adjacent Leroy Well 4 at a depth of 415 m within the Twin Creek Limestone, through which it then migrated to the Leroy #3 well. The gas then migrated up the old Number 3 well to the surface (Araktingi et al., 1984). Repairs were attempted but were unsuccessful and the Leroy Well 4 was eventually plugged and abandoned in 1974 (Araktingi et al., 1984).

In 1974 the estimated stored gas volume ranged between 100 and 110 Mcm, with a pressure close to the original 1500 psig (103 bar/10.3 MPa). During 1975 this was increased to 1830 psig (127 bar/12.7 MPa), around 330 psi (22.6 bar/2.3 MPa) above the original aquifer pressure with circa 246 Mcm of gas stored. During 1978 a surface survey revealed natural gas bubbling in a creek and pond above the storage reservoir site. Several gas tracer surveys were carried out between 1979 and 1981 and proved the gas to be leaking from the aquifer and reaching the surface, sometimes within 9 days of injection (Araktingi et al., 1984; Nelson et al., 2005).

Some of the gas bubbling was observed to be dependent on the storage reservoir operations, stopping altogether during the summer when the reservoir was flooded and did not contain gas. However, elsewhere the gas bubbling was observed to be independent of the storage reservoir operations, which indicated that some of the leaking gas was migrating to a shallow gas collection zone from which seepage to the surface then occurred. Modelling suggested that the second phase of gas migration had started during 1975-76 and that over a period of 130 months storage, a total of circa 17 Mcm of gas had escaped.

Following analysis of the results, it was decided in 1981 that gas loss from the storage reservoir could not be eliminated, but that by limiting the maximum pressure in the reservoir, the leakage rate could be controlled (Araktingi et al., 1984).

The experience at the Leroy facility perfectly represents the problems encountered in aquifer storage reservoirs. These facilities require gas injection at pressures higher than the initial value to displace water from the pores, with gas leakage at the Leroy facility apparently related to a pressure triggered hydraulic seal failure in the middle Thaynes Formation which formed the reservoir cap rock (Katz and Tek, 1981).

The Coalville and Chalk Creek gas storage facilities, Utah, USA

Questar operates two underground sandstone-reservoir gas storage units for peak load demands at Chalk Creek Canyon and Coalville (Morgan, 2004). Gas is stored in porous and permeable Cretaceous sandstone beds; the reservoir unit at Chalk Creek being a sandstone bed in the Kelvin Formation around 550 m below ground, and at Coalville it is the Longwall Sandstone of the lower Frontier Formation around 730 m below ground (Fig. 39). The trap at both storage units is formed by faults and sealed by overlying impermeable shale.

Drilling at the Chalk Creek gas storage unit began in 1960 and in 1973 at the Coalville gas storage unit. Leakage from the reservoirs is indicated by soil gas surveys across the storage fields: reservoir gas is present in the overlying successions, with at least some of the leakage, from the storage fields and from the Pineview Oilfield to the east, linked to faults (Jones & Drozd, 1983).

Pleasant Creek Gas Storage, California, USA

The Pleasant Creek Gas Storage facility is located in the Sacramento Basin of California, to the west of Sacramento (Fig. 40). The storage reservoir horizon is found in a shallow stratigraphic trap at the top of Cretaceous sequences at a depth of 760 m below ground (Hunter, 1955?). Shallow soil gas surveys (circa 10 m depth) across the storage field in the period 1972-1976

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indicated that the natural gas had leaked upwards from the reservoir (Jones & Drozd, 1983; Jones & Pirkle: http://www.eti-geochemistry.com/FinalVersion1.10.htm).

Gas storage facilities in Illinois and Indiana, USA

During the 1970s, more than 16.4 Bcm of natural gas was stored in underground reservoirs at 37 localities in Illinois (Buschbach & Bond, 1974). The numbers currently stand at 29, of which 18 are aquifer storage (EIA, 2006: http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngstorage/ngstorage.pdf). The facilities were operated by a number of operators and constructed in rocks varying from Cambrian to Carboniferous in age, although the majority of the storage volume was in sandstone aquifers of Cambrian and Ordovician age. A number experienced problems and ultimately closed (Fig 41). All were aquifer storage facilities and suffered leaks due to inadequately sealing caprock and problems due to faulting. One further facility at Crescent City in Iroquois County was tested by the Northern Illinois Gas Company during 1967 and was reported as inactive in 1974 (Buschbach & Bond, 1974). Another aquifer storage facility in Indiana was abandoned because the reservoir proved too shallow (Buschbach & Bond, 1974; Perry, 2006). Details are sketchy, but it appears a number of water wells were affected by the intrusion of natural gas that had migrated out of the shallow storage reservoir.

Illinois has around 650 oilfields, located in the Illinois Basin, an elongate intracratonic basin (failed rift) developed mostly in central and southern Illinois, southwestern Indiana, and western Kentucky (Collinson et al., 1988; Kolata & Wilson, 1991). The basin extends about 600 km northwest to southeast and 320 km northeast to southwest, with the greatest thickness of sedimentary fill developed in southern Illinois and western Kentucky, where a maximum of 7,000 m of Cambrian to Permian strata are proved. Hydrocarbons are encountered and stored in a number of reservoir units, which include (Fig. 41): the Cambrian Mount Simon, Eau Claire, Galesville, and Ironton Sandstones, the Lower Ordovician Gunter and New Richmond Sandstones and the Middle Ordovician St. Peter Sandstone. The latter is overlain by the thick, impermeable, regionally extensive, Maquoketa Shale Group, which serves as a major aquiclude (Young, 1992a&b).

Herscher, Kankakee County

A doubly plunging, N-S trending asymmetric Herscher Anticline was delineated by over 100 structure test wells drilled in 1952 by the Natural Gas Storage Company of Illinois (Buschbach & Bond, 1974). Both the Galesville and Mt Simon sandstones are developed as reservoirs. The Ironton Formation, 38 m of sandstone and dolomite, is the caprock to the Galesville Sandstone, itself around 30 m thick at a depth of 533 m. The Mt Simon Sandstone is around 760 m thick at a depth of 747 m, although gas is only stored in the uppermost part and in the Elmhurst Sandstone Member of the overlying Eau Claire Formation (Buschbach & Bond, 1974). The caprock to this reservoir is provided by 60 m of shale and dolomite of the Lombard Member of the Eau Claire Formation.

Injection of gas into the Galesville Sandstone commenced in April 1953 but within 6 weeks, 33 shallow water wells began to bubble gas and injection was stopped (Buschbach & Bond, 1974). The cause of the leakage was not determined with certainty and in 1956 wells were drilled into the reservoir to remove water from the periphery of the gas bubble, to be re-injected back into overlying formations. This enabled regulation and control of pressures in overlying formations, which with the recycling of gas that escaped into the Galena and St Peter sandstones, allowed successful gas injection and storage without significantly raising the pressure in the Galesville Sandstone (Buschbach & Bond, 1974; Coleman et al., 1977).

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Testing of the Mt Simon Sandstone commenced in 1957 and storage began late in 1957, with no leakage detected from the lower reservoir (Buschbach & Bond, 1974).

Manlove (aka Mahomet), Champaign County

The Manlove facility in the NW of Champaign County was developed by Peoples Gas Light and Coke Company in the elongate, N-S trending, La Salle Anticline, around 11 km long and 9.6 km wide (Buschbach & Bond, 1974). Storage was initially attempted in 1961 in the St Peter Sandstone but was discontinued when it was discovered to the south of the crest of the structure that gas had migrated up into glacial drift deposits (Buschbach & Bond, 1974; Coleman et al., 1977). Shallow vent wells were drilled in the area of leakage to prevent the accumulation of gas but despite tests on the structure and the wells, the reason for the leakage was never discovered.

Tests on the Galesville Sandstone reservoir commenced in 1963, but gas was found to migrate up into the St Peter Sandstone and tests were discontinued. At the same time, the Mt Simon Sandstone, which lies at around 1200 m below ground, was appraised and found to be suitable for storage purposes, with 30 m of shaly beds in the overlying Eau Claire Formation providing an adequate seal. Injection of gas commenced in 1964 and the facility was operational in 1966 (Buschbach & Bond, 1974).

Pontiac, Livingston County

Northern Illinois Gas Company began preliminary investigations in 1963 on a N-S trending anticlinal structure 8 km long and 4.8 km wide in the Pontiac area. The Mt Simon Sandstone, more than 600 m thick, provides the reservoir at around 900 m below ground. The caprock is formed by around 40 m of shale and thin dolomite lenses forming the Lombard Member of the Eau Claire Formation (Buschbach & Bond, 1974). However, an intervening shaley, silty sandstone circa 15 m thick provides an incomplete seal, lowering the effectiveness of the facility. Gas was first injected into the Mt Simon Sandstone in 1966 and the facility was operational by 1969, but inactive by 1974 (Buschbach & Bond, 1974).

The higher St Peter Sandstone was also tested for storage potential in 1970 but the caprock could not be guaranteed and any further tests ceased in 1974.

Sciota, McDonough County

Several oil test wells were drilled in the Sciota area, indicating the presence of an anticlinal structure. Tests by Central Illinois Public Service Company in 1971 confirmed the Sciota structure as a NNW-SSE trending anticline in which the Mt Simon Sandstone forms the reservoir at depths of around 800 m. The caprock is provided by 90 m of shaley and sandy dolomites interbedded with shales of the Eau Claire Formation (Buschbach & Bond, 1974).

Testing and injection of about 0.6 Mcm of gas continued in the period 1971-1972 and the facility was abandoned by 1974 (Buschbach & Bond, 1974).

Troy Grove, La Salle County

Between 1957 and 1958, Northern Illinois Gas Company tested a structure in the Troy Grove area. Again tests proved the presence of an anticline 8 km long and 4.8 km wide within the La Salle Anticlinal belt. At least four faults with up to 55 m throw displace the anticline. Within it the Mt Simon Sandstone reservoir is at depths in excess of 430 m, with around 55 m of shale and siltstone in the upper part of the Eau Claire Formation providing the caprock (Buschbach & Bond, 1974).

Gas was first injected in 1958 and the facility was operational in 1959, with gas known to migrate from the Mt Simon reservoir up into sandstones within the lower and upper levels of the Eau Claire Formation since the early development of the reservoir. This resulted in a pressure build up in the overlying strata, which was controlled by withdrawing gas from these zones and reinjecting at depth (Buschbach & Bond, 1974; Hunt, 2004). Until recently, it was thought that the sequences overlying the Eau Claire caprock had prevented the gas from migrating into

D2-253 (Cont.)

shallower sequences, however, a certain amount of gas has been found to reached the surface (Hunt, 2004).

Waverley, Morgan County

An anticlinal structure was known in the vicinity of Jacksonville in the early 1920s and later drilling found oil and gas shows in the structure (Buschbach & Bond, 1974). The structure is domal with three reservoir horizons present: the Ironton-Galesville reservoir circa 10 m thick and 1070 m deep (caprock provided by the Davis Member, circa 21 m thick), the St Peter Sandstone 76m – 90 m thick and 550 m deep, and subsidiary sandstones within the Galena group that generally provides the caprock to the St Peter reservoir. In the early 1950s, Panhandle Eastern Pipeline Company acquired storage rights and began injecting gas into the St Peter Sandstone in 1954, with the facility fully operational in 1961. Injection into the underlying Ironton-Galesville reservoir commenced in 1968.

Gas was found to migrate from the St Peter reservoir through the caprock of limestone, dolomite and thin shale beds of the Joachim Formation and the Platteville and groups into the porous zones of the Galena Group. Further migration appeared to be halted by 60 m of shale in the Maquoketa Group overlying the Galena Group, and the gas was either recycled into the St Peter reservoir or produced (Buschbach & Bond, 1974).

Brookville, Ogle County

Between 1963 and 1964, tests were carried out on the Mt Simon Sandstone in a NW-SE trending anticlinal structure with around 40 m of closure at reservoir level circa 320 m below ground. Around 70 m of the Eau Claire Formation form the caprock and though tests were inconclusive, indications were that communication existed between the Mt Simon, Eau Claire, Galesville and Ironton formations (Buschbach & Bond, 1974). Communication with overlying sandstones was confirmed between November 1964 and July 1965, when 25.3 Mcm of gas were injected into the Mt Simon reservoir. Faulting of the reservoir was seen as the most likely cause of gas migration and the project was abandoned in 1966 (Buschbach & Bond, 1974).

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Leaf River, Ogle County

Between 1968 and 1969, the Leaf River reservoir sandstone was tested in a WNW-trending faulted anticline with around 25 m closure and in which, the caprock was expected to be provided by the Eau Claire Formation (Buschbach & Bond, 1974). The reservoir lies about 250 m below ground. Around 10.9 Mcm (348 m ft^3) of gas was injected with leakage from the reservoir proved by rising water levels in observation wells completed in porous zones above the caprock. Leakage was most likely due to faulting and the project was abandoned in 1971 (Buschbach & Bond, 1974).

Unlined rock cavern, abandoned salt and coal mine gas storage incidents

Weeks Island, Louisianna

The Weeks Island salt mine, excavated in the Weeks Island salt dome formed from the Jurassic Louann Salt around the Gulf Coast, is located around 30 km SE of Jefferson Island. The facility formed part of America's Strategic Petroleum Reserve (SPR) and utilised abandoned room and pillar caverns around 150-220 m below sea level at the Morton Salt Company mine site (Warren, 2006). The top of the salt dome is less than 40 m below sea level (Fig. 42). The mine was purchased from the mining company in the 1970s and was thus not a custom built or designed facility for storing hydrocarbons (Warren, 2006). Following oil fill (1980-1982) the facility stored around 72.5 mmbbls of crude oil.

In 1990-1991, a sinkhole formed over the edge of a salt mine that by May 1992 was 10 m across and 10 m deep (Fig. 42), with a second smaller sinkhole also discovered over the edge of the mine in early 1995 (Neal & Magorian, 1997; Warren, 2006). The sinkholes resulted from a series of geological, hydrological and mining factors, specifically, the mine geometry and excavation-

induced stresses had placed the mine periphery in tension and led to crack development in the overlying strata, perhaps as early as 1970 (Neal & Magorian, 1997). The cracks permitted undersaturated brine to penetrate downwards, which eventually reached the SPR mine workings, dissolving the top of the salt, creating a void, which ultimately caused the collapse of overlying strata.

The 1990-1991 sinkhole was eventually stabilised by the injection of saturated brine directly into the crevasse beneath the sinkhole. This was followed by construction of a freeze wall around the sinkhole to arrest groundwater flow, prior to the stored crude oil being withdrawn (Neal & Magorian, 1997). Investigations revealed that there had been an earlier leak of groundwater into the mine in 1978, adjacent to the sinkhole that had been arrested at the time by injection of cement grout into the flowpath (Warren, 2006). The stored crude oil was withdrawn, leaving around 1.47 mmbbls in the facility, which was plugged and abandoned post-1999 (Warren, 2006).

Leyden, Arvada, Jefferson County, Colorado

The Leyden coalmine is located near Arvada, Colorado some 14 miles NW of Denver and has been described by Raven Ridge Resources (1998). It lies 250 m east of the Leyden Hogback, a N-S trending monoclinal structure on the western margin of the Denver Basin (Fig. 43). Cropping out along the monocline are near vertical Upper Cretaceous strata including the Pierre Shale, the coal-bearing Laramie Formation and the Fox Hills Formation. To the east in the region of the mine, the dip of the strata reduces to near horizontal over a distance of circa 366 m, such that the coal seams lie at between 244 m and 260 m below ground level. The mine occupies an area approximately three miles wide and two miles long. Up to 6 million tons of subituminous coals were mined by room and pillar method from the A and B seams, which occur in the lower 61 m of the Laramie Formation (Fig. 43), which otherwise comprises a series of water saturated shales and sandstones providing the seal to the gas held in the old workings.

In 1960 permission was granted to inject and store natural gas in the mines. This facility was run by the Public Service Company (PSCo) of Colorado, and latterly Xcel Energy, to support its natural gas distribution and delivery operations in the Front Range area of Colorado. It represented the only underground natural gas storage facility made from an abandoned coal mine in the United States, until it ceased operating in 2001. During operation, up to 99.1 Mcm of gas were stored at pressures of between 170 and 250 psi. The pressures were too high and led to loss of gas, which it is alleged, the company were aware of from an early stage.

In the 1990s studies indicated that natural gas had leaked through coal seams and sandstone, and into underground water, generating a plume of gas above the coal mine. PSCo subsequently lost a court case that included the award of $278,000 in punitive damages. During the case, it emerged that PSCo knew of gas leakage from a well only a few years after the facility opened, and of cracking and leakage in the majority of other wells. Gas had also been discovered bubbling up in a number of wells.

Due to the encroaching residential and commercial development in the surrounding areas PSCo announced in early 2000 that they intended to close the facility, the plan being to flood the gas storage facility, creating a major underground reservoir capable of supplying the city of Arvada. Decommissioning of the facility commenced during 2001 and in November 2003 Xcel Energy started flooding the underground caverns with the process planned for completion by 2005. Again no reports of progress were found at the time of this study.

Crossville Storage Cavern (abandoned mine), Crossville, Illinois, USA

The Crossville Storage Cavern in Crossville, Illinois, represents what was described as 'a shallow cavern' constructed to a depth of around approximately 60 m and which experienced some leakage over most of its 30-year life (Pirkle, 1986, Pirkle and Price, 1986, Jones and Burtell, 1994). In fact it appears to be an old shallow mine, with a series of drifts (tunnels) that

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operated as a storage facility for a period of 20 years prior to 1981 when investigations into gas release were initiated (Pirkle & Jones, 2004).

Leakage from the shaft was suspected, but leakage from one or more of the cavern drifts was possible. Between 1981 and 1982, in order to determine, monitor and locate the gas leakage point, an array of up to 450 shallow wells 3 to 4 m deep was constructed as part of a soil gas monitoring project. The cavern was refilled with propane to its original pressure and following recharge propane was observed within the observation test holes within 15 days. An area of contamination 185 m in diameter was detected, which was not symmetrical about the shaft. However, the propane background made it difficult to be certain the product reappearing at the surface came directly out of the reservoir during the sampling time period. In 1982 nitrogen and a helium tracer were also injected, with a helium spot detected around the shaft during the first day. Within 15 days helium had also reached ground surface and the peripheral areas of the earlier hydrocarbon spot. Helium leakage was also found at the end of one of the drifts (Pirkle & Jones, 2004).

Following the helium injection test, it was concluded that cavern leakage was quite rapid and largely associated with the cavern shaft. Within the overburden migration was pressure driven having occurred along faults, fractures and joints (Pirkle, 1986; Pirkle & Price, 1986; Pirkle & Jones, 2004). It was also found that the propane in the near surface sediments migrated into the atmosphere as a function of diurnal changes in barometric pressure (Pirkle, 1986; Pirkle & Jones, 2004).

Anderlues, Belgium

The Anderlues coalmine is located in the Hainaut coalfield of southern Belgium (Piessons and Dusar, 2003). It was operational between 1857 and 1969, after which it was closed down, although the drainage facility was maintained. Gas storage operations began in 1980, with gas stored at low pressures (0.35 MPa) between 600 and 1100 m depth. However, operations ceased in 2000 due to connectivity with shallower mine levels through which gas escaped to overlying strata, highly costly maintenance work on shafts and the high adsorption levels of the gas onto the coal seams (Piessons and Dusar, 2003).

Ravensworth, Virginia, USA

Brief details exist of a product release incident on 24 August 1973 at what was described as an 'unlined underground cavity' at the Ravensworth Propane Storage Facility (Berest, 1989; N Riley, HSE pers com 2007). The facility is presently operated by Washington Gas Light Company and believed to be in Virginia, USA.

The propane was stored in an unlined underground cavity, around 130m below ground level with a capacity of approximately 50,000 m^3. Cavern storage operations continued whilst water was injected in the vicinity of the well in an attempt to stem and alleviate the emissions.

At the present time, there are three different underground gas storage facilities in operation in Virginia. Two of the facilities store natural gas; the Early Grove Gas Storage Field utilizes a depleted gas field, whilst the Saltville Storage Field uses salt caverns. The third, Washington Gas Light Co.'s underground storage facility, stores liquefied petroleum gas in a rock cavern, indicating it to be different to salt cavern and from the White Paper citation, is likely to be an abandoned coal mine (EPA, 1998; http://www.epa.gov/cmop/pdf/own001.pdf).

Depleted oil or gasfields and converted oil or gasfield gas storage incidents

This section deals with two types of leakage associated with depleting/depleted oil and gasfields:

- Mature or depleted fields with old infrastructure
- Depleting/depleted fields converted to gas storage facilities

D2-253 (Cont.)

The distinction is drawn because old fields not associated with gas storage can represent hazards, providing pathways to the surface for remaining gas. In the second instance, the fields can be old or examples where production has ceased relatively recently and in which gas storage is currently ongoing or proposed.

Los Angeles Oilfields, California (USA), including Playa del Rey

Oilfields of the Los Angeles area

The Los Angeles region has been an area of intense hydrocarbon exploration and production since the latter part of the 19th Century (Chilingar & Endres, 2005). Over 70 oilfields have been discovered, most of them in the early part of the 20th Century, with hundreds of oil wells having been drilled from derricks that once blanketed the landscape. The majority of these oilfields are now abandoned, but the area has been left with a legacy of old wells, the locations of which are often poorly known, but that now lie beneath densely populated urban areas (Figs 22&23).

The Los Angeles basin is a deep, sediment filled structural depression with recent alluvial deposits overlying older Cenozoic (Tertiary) age sedimentary rocks, with major through-going fault zones (Fig. 44). It was formed during rifting that commenced in early Miocene times, forming a series of basins and basement highs, the latter comprising the Catalina Schists and granites (Fig. 24). These basement rocks were a source of the Puente and "Repetto" Formations, which form a thick sequence of coarse clastic sediments unconformably overlying the basement rocks and deposited by late Miocene and early Pliocene fan systems. The sedimentary rocks have been uplifted, tilted, and folded by compressive movements between the North American and Pacific plates to produce structures that have trapped and accumulated oil and gas, resulting in numerous oil and gas fields within the basin (Fig. 44).

Oilfields in the Los Angeles area provide numerous instances of potentially explosive methane gas seeping to the surface and raising the possibility of a major incident. This problem has been most vividly illustrated at, for example, Fairfax and La Brea Tar Pits (the Old Salt Lake Oilfield), Belmont (the Los Angeles City Oilfield) and Ballona Wetlands (aka Playa Vista) lying above the Playa del Rey Oilfield (Hamilton & Meeham, 1992; Renwick & Sandidge, 2000; Chilingar & Endres, 2005).

The majority of gas leaks and explosions have been linked to the failure to accurately locate corroded old wells that now leak and with faults that provide the escaping gas with pathways to the surface. Problems were worsened by injection of wastewater at Fairfax and with gas for enhanced oil recovery in the South Salt Lake Oilfield near Fairfax (Hamilton & Meeham, 1992; Renwick & Sandidge, 2000; Chilingar & Endres, 2005).

Salt Lake Oilfield leading to the Fairfax and Belmont gas leaks

The danger of gas seeping to the surface from the Los Angeles oilfields was demonstrated at Fairfax, LA, in March 1985, and again in 1989 (Fig. 22a). The area overlies part of the Salt Lake Oilfield, which was once developed by more than 400 wells. The field was largely abandoned but redeveloped by slant drilling during 1962, with the continuous production of oil, salt water and gas thereafter. Water has been re-injected into the field since 1980. In March 1985, methane that had accumulated in the basement of the Ross Department Store ignited and caused an explosion that injured 23 people. Fires also broke out along surface cracks and fissures that developed nearby. The escaping gas originated from the oilfield lying immediately beneath the area and had migrated up along at least two wells and the Third Street Fault that reached surface beneath the department store. One of the wells was an old abandoned vertical well, but the second was a relatively modern inclined well that was found to have suffered corrosion below 366 m depth (Chilingar & Endres, 2005). The gas had leaked to the surface via a shallow 'collector zone' at around 15 m and continued to emerge through the pavement and surrounding

D2-253 (Cont.)

areas and burned for many days after the explosion. High levels of gas were also found at a nearby school.

A very similar gas leak incident occurred on February 7th 1989 across the street from the 1985 explosion (Chilingar & Endres, 2005). The causes were found to be old corroded wells, blocked ventilation wells and ongoing oil and gas production. Quick actions and safety measures prevented a repeat of the 1985 fire and explosion. It is believed that the 1985 and 1989 Fairfax gas leaks were the result of waste disposal or secondary recovery operations initiated by pressure injection of oilfield wastewater back into the fields (Hamilton & Meehan, 1992). This has led to increased pressures, driving the gas out and up old wells with poorly completed or corroding and deteriorating steel casings and cements. It is suggested that increased pressures also periodically cause migration along the Third Street Fault, further exacerbating the situation (Hamilton & Meehan, 1992).

A further leak and potential major hazard was detected in 1999 at the intersection of Wilshire and Curson streets just south of the La Brea Tar Pits, (which are about 1.6 km from the Fairfax incidents). Again, it was found that high-density commercial buildings had been developed in an area with old abandoned wells, requiring the installation of specialised ventilation equipment to prevent the build up and explosion of gas (Chilingar & Endres, 2005).

Further gas migration problems were identified during the $200-million Belmont High School development, in Northwest downtown Los Angeles (Fig. 23b). Conceived in 1985 and dogged by trouble and delay, building finally commenced in 1997, but was halted by the discovery of high levels of methane in the soil across the site. The gas originated from the underlying Los Angeles Oilfield and controversy raged over whether the school could be safely completed or not. Geological investigations revealed the presence of a fault below the school site that might provide a pathway to the surface and district officials questioned the completion of the project as planned. Archival photos of the area circa 1890 show hills blanketed by oil derricks, the majority of sites of which are not documented and are now covered by homes, business premises and the site of the school (Fig. 23). A decision to cease further building and abandon work on the school was taken in January 2000, although pressure remains to recommence work.

In 2001 operations commenced to inject gas under elevated pressures into the producing reservoir of the South Salt Lake Oilfield (Fig. 44) in order to enhance oil recovery. However, in January 2003, serious gas leakage problems were discovered near the Fairfax area in the vicinity of Allendale and Olympic Boulevard. The gas had been leaking to the surface along abandoned and poorly completed wells drilled before official records were kept. Consequently, the existence and abandonment status of many of these wells was unknown and high-density housing (largely apartment buildings) had been developed over them (Chilingar & Endres, 2005).

Gas leaks at the Montebello and Playa del Rey oilfields

The Fairfax and Belmont gas leaks are of particular interest when incidents at the Montebello and Playa del Rey (PDR) oilfields gas storage facilities are considered. Again, Montebello and PDR represent oilfields with a long history of oil and gas exploration and production, which has included the drilling decades ago of hundreds of unregulated (or monitored) operational or abandoned oil/gas wells (Fig. 22b&e). Many of these wells were drilled before today's rigorous drilling and completion standards were implemented or applied (Chilingar & Endres, 2005).

In the case of Montebello, gas had been injected at a depth of around 2286 m and was subsequently found to be leaking to the surface along old wells, again, many of which were drilled in the 1930s (Chilingar & Endres, 2005). Investigations have revealed that the old well casings and cements are unable to cope with the increased pressures, allowing high-pressure gas to enter the old wells and migrate to shallower depths but not to the surface (Benson & Hepple, 2005). The problems encountered meant that the facility was eventually closed in 2003 (Chilingar & Endres, 2005; EIA, 2006).

D2-253 (Cont.)

The PDR Oilfield, is developed in the western Los Angeles Basin, about 17.6 km (11 miles) west-southwest of downtown Los Angeles, circa five miles south of the Santa Monica Mountains and five miles north of Palos Verde Peninsula hills to the south (Fig. 44). The discovery well for the PDR Oilfield was drilled in 1929 by the Ohio Oil Company and by the end of 1930, 141 wells had been drilled in the area (Barnds, 1968). Fifty more were drilled between 1934 and 1935, with the result areas became densely covered with oil derricks (Fig. 22b) and the precise total of operational or abandoned oil/gas wells across the field being unknown, but somewhere between 200 and 300 (Fig. 22e). The PDR Oilfield quickly depleted and in 1942, as part of the wartime effort, it was converted for use as a gas storage facility, full-scale operations having commenced in June 1943 (Barnds, 1968). PDR continued to be used as a storage facility and since 1945 has been operated by Southern California Gas (SoCalGas). The storage field is presently operated through 54 directionally drilled wells, of which 25 are injection/withdrawal wells used to inject and extract gas, 8 are liquid (primarily water) removal wells, three are lateral migration wells to control gas movement, and 18 are observation wells used to monitor pressure and liquid saturation.

The PDR oilfield lies on the western shelf of the Los Angeles Basin (Figs 24&44), between the Newport and Inglewood Fault Zone to the east and the Palos Verdes Fault offshore to the west (Wright, 1991). Many active faults are known within 80 km (50 miles) of PDR, including the Charnock Fault to the east of the oilfield (Biddle, 1991). The PDR Oilfield comprises two accumulations separated by a NW-SE trending ridge.of basement (Mesozoic - Jurassic?) rocks referred to as the Santa Monica or Catalina Schist: a northwestern 'Ocean Front' or 'Venice Beach' accumulation and a southeastern accumulation, known as PDR that extends north of the Ballona Creek (Eggleston, 1948; Landes et al., 1960; Barnds, 1968). The Venice section of the field produces from the sandstones of the "Reppetto Formation" (Pliocene), and a basal schist conglomerate (Topanga Formation) of Miocene age (Fig. 24), plus or minus fractured basement (Landes et al., 1960). Production in the PDR area is mainly from the basal zone only at around 1830 m below ground (SoCal, 2004), but oil has been encountered at higher levels in Lower Pliocene deposits (Barnds, 1968).

Within the oilfield, small scale faulting of the basal schist conglomerate and Puente Formation is known (Wright, 1991). More recently, a north-south linear trend (518 m long and 61 m wide) of high methane concentrations has led to the suggestion that a downwest fault (the Lincoln Boulevard Fault) exists in the potential storage area (Exploration Technologies, 2000). The fault has been linked to the substantial leaks of methane from the gas reservoir, which would be intersected at around 1830 m and would provide a permeable vertical migration pathway to the near surface, where it is trapped in the shallow gravel beds. However, the existence of the fault has been questioned (Davis & Namson, 2000).

The PDR area has been the focus of attention since the 1990s as land in the Venice, Ballona Creek and PDR areas, overlying the PDR oilfield is being considered for major urban development (e.g. Chilingar & Endres, 2005). The depleted oilfield is one of five gas storage facilities within a 64 km (40 mile) radius operated in the Los Angeles region. There are numerous documented instances of gas leaking to the surface at PDR, with leaks and surface seepage documented in 11 wells in the general PDR and MDR area (SoCal, 2004). Gas is also seen bubbling up in waters of the Marina and Ballona Creek/Channel and following heavy rains, in standing water (Chilingar & Endres, 2005). Some wells lie in shallow lakes and gas is seen bubbling up alongside old well casings (Fig. 22d). Analyses of the gases from the Ballona Creek and other leaks indicate that it is seeping up from deep underground.

The change of land use has inevitably led to problems, with the Playa Del Rey area the centre of a major ongoing battle to prevent the development of a large housing project over the oilfield. When excavations began for the actual construction of the housing development, it was discovered that wells, abandoned as recently as 1993 to make way for the housing development, were found to be leaking (Chilingar & Endres, 2005). In each case, homes were constructed over

D2-253 (Cont.)

the old wells after minimal efforts were taken in an attempt to reseal the wells. There have also been efforts to install a membrane in an attempt to stop the migration of gas into buildings.

Investigations revealed that gas has leaked from the reservoir, both into the adjoining Venice accumulation and also upwards since the earliest days of operation (Reigle, 1953; Chillingar & Endres, 2005). In the latter case, the gas migrates to an intermediate sandstone horizon (Pico Sand) between 610 m and 915 m below surface (Fig. 22f). From here it finds its way into the "50 foot gravel zone" (Los Angeles riverbed deposits) via fractures and old abandoned and capped wells that have cracked or corroded casings and cements and thence to the surface. Within the gravel zone, flow rates may be as high as 20-30 litres per minute (Chillingar & Endres, 2005). Estimates for the rate of gas loss due to uncontrolled migration and/or seepage into the atmosphere from the Playa del Rey oilfield are put at approximately 2.8 Mcm per year (Tek, 2001; http://www.saveballona.org/expert.html).

Opponents to the Playa Vista development have also cited corporate reports from the 1950s, indicating that millions of cubic feet of gas had disappeared. Furthermore, the driving of piles for some of the larger buildings up to 15 m down through the poorly consolidated river terrace and wetland marsh sediments into solid rock could provide more pathways for the migration of gas. Opposition groups have, therefore, allude to the Fairfax and Belmont incidents, highlighting the problems of gas seepages and perceived danger of explosion, with old wells and possible unknown faults in the area, as reason for the abandonment of any further development. Consequently, the problems associated with the PDR gas storage facility are not so much with previous high profile leaks and explosive incidents at the site, but with potential disasters. The Playa Vista development and associated problems clearly highlight the difficulties encountered with urban encroachment into areas historically reserved for oil and gas field operations, not just within the Los Angeles Basin, but anywhere with historical oil production (Chilingar & Endres, 2005).

D2-253 (Cont.)

Playa del Rey gas storage incident

There is one documented incident of a rapid escape of stored natural gas at the SoCal storage complex in PDR. This occurred at about 6:10 am on the morning of 2nd April 2003, when a mechanical valve failure led to a 25-minute venting of gas mixed with some accumulated oil, that left cars, streets and homes coated with a brown residue (Peterson & Marquez, 2003; http://www.saveballona.org/gasoilmist.html). Local residents described a loud rushing noise and a geyser rising up to 30 m into the air. SoCalGas described the incident as the first of its kind in the 60-year operating history and resulted from the triggering of a safety mechanism that vented gas following the breakdown of a compressor.

East Whittier Gas Storage Facility, California

The East Whittier oilfield, lying to the ESE of the Montebello Oilfield in eastern California (Fig. 44) was discovered in 1917 and converted to a gas storage facility in 1952. The facility was operated by SoCalGas, with additional wells drilled and operated for the purpose of gas storage and withdrawal. Although no surface leaks were reported for the East Whittier facility, it was found during the 1970s that the storage gas had migrated out of the original storage area within the SoCalGas lease area, into an adjoining lease and was being produced and sold by another company (Benson & Hepple, 2005). The injection of gas ceased in about 1986, with gas injection facilities dismantled and removed from the site in 1992. SoCalGas continued withdrawal of gas until final closure and abandonment of the site accompanied closure of their Montebello storage facility in 2003 (Benson & Hepple, 2005; EIA, 2006).

El Segundo, California

The El Segundo Oilfield, located southwest of Los Angeles, represents a faulted anticlinal trap, with two distinct accumulations separated by a northwest trending zone of faulting (Eggleston, 1948; Landes et al, 1960; Khilyuk et al., 2000). The first well was drilled to the east of the faulted fracture zone in 1935 and produced oil from the Miocene Basal Schist Conglomerate

(refer Fig. 24) at a depth of around 915 m (Khilyuk et al., 2000). Production from the western part of the field began in 1937 from fractured Basement Schist at around 2210 m (Landes et al., 1960). Sixty-six wells were drilled in the development of the El Segundo field with a wide variation in production from adjacent wells (Eggleston, 1948; Landes et al, 1960).

In the early 1970s, gas was stored in the depleted oilfield, however, gas detected in a nearby housing development that was under construction indicated that the gas had migrated out of the reservoir. Construction was halted and a passive venting scheme was installed in an attempt to prevent the dangerous build-up of gases and a decision taken to close the storage facility (Khilyuk et al., 2000).

Castaic Hills and Honor Rancho oilfields, California

The Castaic Hills and Honor Rancho oilfields are two of a cluster of oilfields located to the east of Ventura in Los Angeles County, California. Both are depleted oilfields that were converted to gas storage fields and are operated currently by SoCalGas (Figs 22c&45). It is noteworthy that several hundred exploratory and development wells have been drilled in the Honor Rancho field, adjacent oil fields and the surrounding area (Davis & Namson, 2004).

The Castaic Hills and Honor Rancho gas storage fields are located in the eastern portion of the Ventura basin; a highly deformed Tertiary age marine basin within the Transverse Ranges of southern California (Davis & Namson, 2004). The major through going San Gabriel fault is present circa 1 km to the northeast of the storage field, separating the mostly marine eastern Ventura Basin on the west from the mostly nonmarine Soledad Basin to the east. The deepest part of the eastern Ventura basin occurs just west of the storage field. Nonmarine Saugus Formation (Quaternary age) crop out at surface. To the SW, lie the Castaic Junction and Newhall Potrero oil fields, traps for which are late Pliocene and Quaternary anticlines along the southwest margin of the eastern Ventura basin.

The Honor Rancho Storage Field, located in Valencia, near the intersection of Interstate Highway 5 and State Highway 126 in the northwest part of Los Angeles County (Fig. 45a), was known as the Southeast Area of the Honor Rancho Oil Field (Davis & Namson, 2000). The field was discovered by ChevronTexaco in May 1956, when oil and gas was encountered in a series of sandstones (including the Wayside 13 sand) at depth of approximately 2.5-3 km below ground level (Fig. 45b). The Wayside 13 sand is the basal unit of a sequence of deepwater shale and turbidite sands forming the shale dominated upper Miocene to lower Pliocene Towsley Formation (Davis & Namson, 2004). The up-dip seal is provided by a down-to-the-north syndepositional normal fault (active during Towsley deposition), with the Towsley Formation faulted against the Wayside 13 sand. However, the nature and exact location of the east and west lateral seals are less well known. Initial reservoir pressures were 4411 psig. Between 1956 and 1975, ChevronTexaco drilled 23 further wells on the field. Structurally, the field lies in the footwall block of the east-west trending Honor Rancho thrust of late Pliocene and Quaternary age and is underlain by a further concealed reverse fault (F-1), from which the Honor Rancho structure arises (Davis & Namson, 2004). The Honor Rancho thrust fault and F-1 reverse fault intersect the San Gabriel fault just to the east of the storage field and probably continue westward as blind faults beneath the north side of the Ventura basin to connect with the San Cayetano fault system.

In 1975, SoCalGas acquired the Southeast Area of the Honor Rancho Oil Field from ChevronTexaco and converted the field for gas storage in the Wayside 13 sand. It was renamed the Honor Rancho Storage Field with 38 wells presently completed to the storage zone: 23 combination injection-withdrawal wells, 8 withdrawal-only wells and 7 oil wells equipped with gas lift (the WEZU-13A is completed outside the storage zone, and WEZU-C4 is currently plugged-back and idle; Davis & Namson, 2004). All of the wells acquired from ChevronTexaco were reworked and 17 combination injection-withdrawal wells were drilled by SoCalGas. Each well is equipped with a wellhead safety shutdown system and lateral pipework that can be used to kill the well remotely.

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The Castaic Hills Oilfield lies just to the west of the Honor Rancho Oilfield, having similar structural position and reservoir characteristics. After depletion, it was used for gas injection. However, production of gas from the Honor Rancho and Tapia fields with similar chemistry to that of the injected gas at Castaic, indicated that gas was migrating out of the storage reservoir and eastwards into producing reservoirs of the Honor Rancho and Tapia fields at shallower depths (refer Fig. 45). Dying oak trees along the surface trace of faults indicated that gas was then migrating to surface via faults (Khilyuk et al., 2000). There are no reports found of any adverse impact on humans thus far.

McDonald Island, Stockton, San Joaquin County, California

The McDonald Island gas storage facility is a depleted gasfield operated by Pacific Gas and Electric (PG&E) some 360 miles north of the Los Angeles storage sites described above (Fig. 22c). The facility is the largest of PG&E's underground gas storage fields, providing approximately 25% of available gas supply during cold winter weather in the PG&E service area (Menconi & Sanders, 2006). Onsite there are above ground gas processing, compression and metering facilities used during the injection and withdrawal of gas from the gas storage facility.

Discovered in 1936 by the Standard Oil Company, the McDonald Island Gasfield produced gas from an early Eocene (Cainozoic) sand, the top of which was at 1670 m below ground level (Lee, 1968). The field is a relatively simple NNW-trending faulted anticline and initial wellhead pressures were 2,086 psig. Five further wells were drilled and the field produced from 1937 to February 1958, by which time the pressure had declined to 450 psig. Thereafter, five further wells were drilled and the field was converted to gas storage purposes, with the field rights transferred to PG&E on December 11th 1958 (Lee, 1968). The field is currently operational with a storage capacity of around 3.34 Bcm (Habel, 2005).

Reports are limited, but there have been two cases of explosions and fire at the facility. The first incident occurred in 1974 with the resultant fire consuming an estimated 0.42 Mcm of natural gas over a 19-day period (San Joaquin County, 1992).

The second explosion occurred on 1st October 1993 and was heard up to twenty miles away. The incident resulted from an explosion in a moisture extractor, where natural gas is processed prior to injection and after withdrawal from storage. Debris from the incident was thrown up to one-mile and caused damage to property, cars and boats over that distance (Delta Protection Commission, 1997). The incident resulted in a 40% production loss and caused site damage of US$2 million and third party damage of US$50,000. The ensuing fires were extinguished by the facility's automated fire-extinguishing system.

Search for oil at UGS facility, southern Illinois (USA)

Sketchy court reports exist of an explosion and fire that occurred on February 7th, 1997, at an oil well drilling site located over an underground gas storage field in southern Illinois. According to the plaintiffs in a court case, Petco Petroleum Company (Petco) began drilling Orville Mills Well No. 6 well site (owned by the defendant Bergman Petroleum) in the search for oil. The claim was that no inspection was carried out at the well site before drilling began to ensure site safety. Later inspections revealed that the well was unsafe, but the drilling was not stopped. Natural gas migrated through the sandstone in the area, and on February 7, 1997, gas erupted from the well, resulting in an explosion and fire. The three employee plaintiffs were all injured in the explosion and they argued that the explosion occurred because the defendants:

- failed to follow applicable safety regulations
- failed to have a working blowout preventer at the site to seal the well
- failed to correct unsafe drilling practices at the site
- directed Petco employees to continue drilling in spite of a known and imminently dangerous situation.

D2-253 (Cont.)

The case was dismissed as the plaintiffs did not allege facts sufficient to raise a duty on the part of defendants to keep the job site safe and show sufficient violation of that duty.

Epps Gasfield, Louisiana, USA

The Epps Gas Storage Facility, operated by Trunkline Gas Company, is a converted gas field located in what were originally defined as two different fields; Epps and South Epps in the East and West Carroll Parishes of northeastern Louisiana (Coleman, 1992). The Epps Gas Field was discovered in 1928 and between 1928 and 1973, produced gas from the Monroe Gas Rock at a depth of approximately 700 m. The Monroe Gas Rock (MGR) in northeastern Louisiana represents the last stage of Mesozoic carbonate platform development in the north-central Gulf province (Washington, 2006). Another gas field, also producing from the Monroe Gas Rock, was discovered southwest of the original field in 1954. This field, known as South Epps, produced until 1972 Depletion of both fields led to gas production ceasing in 1973, when Trunkline Gas Company converted both fields to gas storage facilities. Injection of storage gas commenced in 1979 and between 1984 and 1987, 11 production wells were drilled in the west that by 1989 had produced over 56.6 Mcm of gas.

However, geochemical fingerprinting of the gases in the field(s) demonstrated that chemical and isotopic composition of the gas in some of the western wells had, over time, changed from that of native gas to that of storage gas. This meant that a majority of the gas produced in the western area was not native gas, but storage gas, which had migrated into the western area (Coleman, 1992). Following further studies in 1990, the boundaries of the storage area were redefined to include these producing wells and thus protect the integrity of the storage project. The facility remains operational (EIA, 2006).

Rough Gasfield, southern North Sea, UK Sector

On the 16th February 2006, an explosion followed by the outbreak of fire occurred on the Bravo 3B platform of the Rough gas storage facility in the southern North Sea (Centrica, 2006). The storage facility is about 31km (20 miles) off Withernsea on the East Yorkshire coast and was originally developed in October 1975, as the Rough Gasfield, to produce natural gas from the Permian Rotleigend sandstone reservoir at around 2750 m below the seabed.

The explosion occurred at approximately 10.30 in the morning, which led to the evacuation of 31 of the workers, including two who suffered burns and smoke inhalation and were treated in hospital. Twenty-five essential staff remained on the platform, whilst the fire was put out. Production on both the Bravo and Alpha platforms was halted whilst the Bravo platform was depressurised and made operationally safe. The shutdown caused wholesale prices to rise by 40%, however, these quickly fell back again as more details emerged. The incident is under investigation by the HSE and HSL, with final details of the cause of the explosion and fire yet to be released. However, the HSE released a safety alert in May 2006 (HSE, 2006) advising the incident leading to the explosion involved the catastrophic failure of a shell and tube heat exchanger (cooler unit) seemingly in close operation with one of the four glycol dehydration units (refer Centrica, 2006).

Fort Morgan, Morgan County, Colorado, USA

Colorado Interstate Gas Company (CIG), part of El Paso Corporation and operators of the Fort Morgan Storage Field in Morgan County, Colorado, announced that a well leak had occurred at its storage facility on Sunday 22nd October 2006. It led to a partial shutdown of operations, pending further investigations. The plant was shut down for a week after the leak, but was back online by the 9th November (State of Colorado, 2006; http://tonto.eia.doe.gov/oog/info/ngw/ngupdate.asp).

The field, one of five in the Rocky Mountain division, covers an area of around 3,220 acres (1303 ha) and was originally discovered in 1954. In 1966, following 10-12 years of production, it was converted for storage purposes, with 34 wells used to store almost 424.8 Mcm of natural

D2-253 (Cont.)

gas. The gas storage field plays an important role supplying homes, schools, businesses, hospitals and power plants with natural gas in both Fort Morgan and along the Front Range.

Reports that water and gas were bubbling to the surface were received by both CIG and El Paso at about 12:30 pm on October 22nd 2006. Surrounding roads were immediately closed, with investigations into the leak beginning early on October 23rd, with a systematic testing of wells to determine where the gas was leaking. Methane was leaking into an aquifer and it was feared that it could enter houses with well water and find an ignition source. Thirteen families in houses using water wells within a 1600 m radius of the leak were evacuated and put into local motel accommodation. By the following Thursday, residents of all but the two houses closest to the well were allowed back into their homes, with the two remaining families still in motels on 9th November.

Initial investigations revealed that the source of the leak was at a depth of about 1600 m in well No. 26, located in the middle of the field. The leaking gas migrated up the well and vented to the surface, via an intermediate level, in two general areas to the southwest and southeast of the plant. Following the leak, well pressures were monitored twice a day, results of which indicated no other well leaks. Currently no information is available as to how the leak was plugged.

Breitbrunn/Eggstatt, Bavaria, Germany

The Breitbrunn/Eggstatt Gasfield in Bavaria, Germany, was discovered in 1975 and produced from four sandstone reservoirs via four vertical wells. Production ceased in 1993 following which, the uppermost reservoir was converted to gas storage with the drilling of 6 horizontal wells that together, doubled the storage capacity to 1.085 Bcm [38.3 Bcf] (Bary et al., 2002; Rohler et al., 2004). Two deeper reservoirs were ultimately converted for gas storage to increase storage capacity as gas demand grew during the winter months.

During 2003, an anomalous pressure was noted in the Breitbrun 21 gas storage well that indicated a leak in the borehole completion (Üherer et al., 2004). In order to investigate and locate the potential leakage point, fibre optic temperature measurements were performed in June and October 2003. These measurements showed a significant temperature anomaly at a depth of 586 m, which was caused by a leak in the borehole string. According to the tubing list a pipe joint is located at this depth (Üherer et al., 2004). The leak was repaired using a sealing sleeve, demonstrating a process that offers potential for companies operating gas and gas storage wells elsewhere.

Bammel Oilfield, Texas (USA) and Hatfield Moors Gasfield, South Yorkshire (UK)

Although not strictly gas storage incidents, the Bammel Oilfield (Texas) and Hatfield Moors Gasfield (South Yorkshire) provide examples of major well blowouts at operating fields that have subsequently been converted to successful gas storage facilities.

Between 1942 and 1945 a spectacular blowout occurred from a casing leak in an oil and gas well at the Bammel Field, Harris County, Texas. In the mid 1960s after depletion of the oil and gas reserves, the Bammel Field, which lies to the NW of Houston, was converted to an underground natural gas storage field. It presently represents one of the largest underground reservoir storage fields in North America, being strategically located on the HPL system in Houston in close proximity to the Katy Hub. As a result of the leak, the surrounding fresh water aquifers were badly polluted by oil and gas from the well. The incident served as a scapegoat for most of the reported cases of petroleum contamination in water wells in northern Harris County (LeBlanc & Jones, 2004).

The Hatfield Moors Gasfield was discovered accidentally in December 1981 when drilling the Hatfield Moors No.1 exploration well. The hole had reached a depth of 424 m (1587 feet) in the Westphalian B Oaks Rock sandstone formation, when during operations to change a drill bit, there was a major gas escape that ignited. There were no casualties, but the ensuing blaze

D2-253 (Cont.)

destroyed the drilling rig, and the fire was not brought completely under control until 38 days after the initial explosion, by which time around 28.3 Mcm of gas had been consumed in the fire (Ward et al., 2003). Gas had not previously been known in the Oaks Rock in the many coal and several oil boreholes that had already penetrated this shallow formation in this area. Hatfield Moors was successfully developed and produced gas for a number of years before being converted to a gas storage facility in 2000 (Ward et al., 2003).

Gas storage well damaged during earthquake and drilling activities

A specialist drilling firm, Vector Magnetics (http://www.vectormagnetics.com/casehistories.pdf), record instances of damage to gas storage wells in Southern California that required correction by sidetracked wells. Unfortunately, the precise locations of the incidents have not been ascertained, but they are noteworthy as having been associated with UGS.

The first instance involves a directionally drilled gas storage well in which collapse of casing and tubing across a sand/shale boundary below circa 2135 m had been caused by an earthquake (Fig. 46a&b). Safe abandonment of the well following retrieval of the pipe string and cementation was achieved by sidetracking out of the well and re-entering below the collapsed section of well.

The second instance of damage to a gas storage well occurred during work to repair a casing shoe leak when a gas utility inadvertently sidetracked out of the 5½ inch casing of a gas injection/withdrawal well (Fig. 46c). The damage to the well servicing a gas storage reservoir at around 3100 m, occurred at a depth of 2255 m. A number of attempts to re-enter the casing proved unsuccessful. The problem was rectified by a sidetracked well out of the original casing at around 730 m, drilled to intersect the 5½ inch casing at 3021 m. The operation then required milling of the well casing and cementing a nine metre section for abandonment, above the level of re-entry, with the newly deviated well completed as the replacement well (Fig. 46c).

The third instance of damage and repair to a gas storage well, again involved a gas utility inadvertently sidetracking through the corroded casing of the storage well that was servicing a reservoir at around 2470 m. In this case, the initial damage occurred at circa 1250 m during routine work-over and casing patch operations (Fig. 46d). Subsequent attempts to re-enter the casing only deepened the sidetrack and resulted in the loss of a drill collar fish tool. The old well casing was by-passed by directional drilling of a new well that re-entered at around 1335 m, following which the old well could be safely plugged and abandoned.

D2-253
(Cont.)

Appendix 6 Risk Assessment - considerations

WELL PROBLEMS

In general, well problems will primarily involve the following:

- breaks/faults in the casing, joints or defective or poor quality cementing of casings, leading to
  - leakage through new or ageing injection well completions
  - leakage up abandoned wells
- presence of unknown wells arising from inadequate site characterization
- during re-entry to, or repair and maintenance work on wells
- Inconsistent or inadequate monitoring of injection wells, groundwater in overlying formations and leakage from abandoned wells.
- Leakage due to inadequate cap rock characterization
- The facility operating at pressures higher than the rock units have previously experienced. In the UK, depleted oil and gasfields, would not normally be operated at pressures above the original reservoir pressure (BS 1998a). Elsewhere one of the main risks and causes of leakage is due to operation of underground aquifer and salt cavern gas storage facilities at pressures greater than the rock has previously experienced (overpressures or 'delta' pressures). This is related to maximising the working gas volume and to attaining higher delivery rates as well as achieving a greater return on investment.
- Inaccurate inventories of stored or injected product

Risk Assessment – failure mechanisms relating to geology

With reference to geological matters, the following would probably be of immediate relevance in the UK context (many such failure mechanisms, outlined for salt caverns but not specific to salt, would also be relevant to the assessment of pore storage options):

SALT CAVERNS

Three principle factors contribute to the breaching and collapse of solution mined salt caverns (cavities):

- salt creep
- uncontrolled leaching
- presence of anomalous zones in what had been assumed to be homogenous salt – including non-halite interbeds

Salt cavern release scenarios, include:

- use of old brine cavities for gas storage (NE England, Cheshire)
  - not designed for storage

D2-253 (Cont.)

- uncontrolled leaching/brining
    - often a lack of roof salt and/or unstable roof – potentia for collapse
    - cavern enlargement – breakthroughs, caverns coalesce
    - cavern and well seal – see below
  - no monitoring of abandoned caverns for subsidence or cavern shape
- inadvertent intrusion - new wells, not necessarily associated with the storage scheme
  - could lead to unexpected, sudden release of product
  - introduced fluids
    - drilling fluids
      - not suitable for salt
      - less saline water – brining possible
    - groundwaters – if well has not been properly cased etc.
- inadvertent intrusion – unknown or poorly sited/located old existing wells, not associated with the storage scheme, intersected by developing cavern
- inadvertent over enlargement of the cavern by brining (uncontrolled brining)
  - during construction – can be monitored
  - during operation – if brine compensation mode is used for cycling product (undersaturated brine pumped in can dissolve salt, enlarging the cavern – American usage/incidents)
- development of solution channels between
  - wells
    - brining wells (during cavern construction)
    - injection wells – most likely when operating in brine compensated mode
  - caverns
    - pre-existing – due to uncontrolled leaching
      - at time of original brining
      - during storage operations when using brine compensated mode
    - developing caverns
      - unidentified geological boundary (?fault/fracture)
      - more soluble (e.g. potash) horizons
    - during gas storage – when operated in brine compensated mode
- inadvertent over-pressurisation of the storage facility
  - not knowing volume of injected gas
    - initially
    - during injection
  - equipment failure

D2-253 (Cont.)

- valves
- pipework
- meters
- compressors
- safety monitoring systems

- leads to fracturing of rock
  - salt
  - more competent interbeds
- escape of product

- inadvertent de-pressurisation below minimum operating pressures
  - during operations
  - during maintenance
  - equipment failure (representative major accident scenarios need to be addressed in the COMAH Safety Report)
    - wells
      - casing – corrosion/fractures/holes
      - cements
    - valves
    - flanges
    - pipework
      - corrosion
      - inadvertent damage
    - meters
  - escape of product
  - damage to
    - cavern walls – microfracturing and spalling of walls
    - cavern roof
    - well seal at top of cavern
- failure of the cavern seal or existing/new well completions
  - failure of the cavern seal
    - caused during brining operations – well shoe and casing
    - after cavern commissioned
      - increased pressure from salt creep (and temperature)
      - lowering of cavern pressure
        - damage to
          - cavern walls – microfracturing and spalling of walls
          - cavern roof

D2-253 (Cont.)

- well seal at top of cavern
- too low an operating pressure
  - damage to
    - cavern walls – microfracturing and spalling of walls
    - cavern roof
- too great a depth (>2000m?)
  - unstable caverns
  - increased creep
  - increased volume loss/decrease

- failure of the well completion(s)
  - between cement and formation/borehole sidewall (rock)
  - between cement & casing
    - outer cement fill
    - well plug
  - through casing
    - fracture/damage
    - corrosion
  - through fractures in outer cement
  - through cement plug
    - deterioration
    - fractures
    - diffusion
  - due to damage during maintenance and repair - redrilling

- Development of ledges/benches within the cavern during brining and cavern construction process
  - Caused by presence of thicker non-halite beds in the bedded salt sequence
    - results from poor initial characterization of the salt sequence and/or brining process
  - leads to 'compartmentalisation' of the cavern
    - cavern performance not as predicted/anticipated
  - could lead to collapse of shelves/benches formed by thicker non salt interbeds, leading to damage to
    - cavern floor
    - cavern walls
    - well string, causing
      - damage to injection/withdrawal wells
      - failure of the cavern seal

D2-253 (Cont.)

- unforeseen change in the dynamics and operation of the cavern
- Development of 'anomalous zones' in salt (Warren 2006)
  - Unexpected zones/regions of highly soluble salts (e.g. potash salts)
  - Zones of much older natural leaching (eg 'black salt') could contain
    - pressurised brine or
    - gas (methane or nitrogen)
  - present the same problems in operational salt mines
- diffusion
  - interbeds
  - cement
    - well plug
    - borehole – cement boundary
    - borehole wall – cement boundary
- release of material/gas through
  - cracks,
  - leaky interbeds,
  - nonhomogeneous zones of higher impermeability
  - along fault planes
    - known
    - unknown
- dissolution of the roof/walls of the cavern due to groundwater ingress
  - wet rockhead conditions
  - through other means – ingress ie at deeper levels
    - along leaky interbeds
      - distant new/old wells intersecting nonhomogeneous zones of higher permeability at shallower levels
      - fractures
    - new/old wells intersecting the salt body elsewhere
      - leakge pathway
      - causing solution channels and pathways (e.g. Myers et al., 1972)
- geochemical
  - groundwater ingress
    - water into gypsum/anhydrite bearing rock
    - water into salt beds
  - geochemical alteration
    - gypsum-anhydrite
      - input or removal of water to the system

D2-253 (Cont.)

        - Volume change effects – cracks etc to associated interbeds?
    - interaction of pressured (dry) gas with
        - cavern wall beds
            - salt
            - other evaporites
            - non salt interbeds – drying effects (cracks)
- caverns connect with other large voids
    - other brine caverns (known or unknown) too close and when
        - operating pressures to high
        - Operating in brine compensated mode, leading to further solution of the cavern walls and hence intervening salt wall failure
    - pre-existing salt mine areas - known or unknown/long forgotten, i.e. old workings, the full extent of which are not known or were never accurately recorded
    - old collapsed brine caverns (e.g. Preesall)
    - pockets of gas in the salt body during
        - operation in brine compensated mode – injected brine causes further unnoticed dissolution of the salt beds
        - during cavern formation – unexpected, potential damage to
            - cavern walls/roof
            - hanging pipestring
- partial cavern roof/wall falls – various causes
    - poorly constructed
        - too little roof salt thickness left
        - too wide a cavern – unsupported roof
        - operating pressure too low
            - microfractures and spalling of cavern walls
            - simple collapse
            - fault development
- reactivation of a fault in the cap rock
    - hydraulically induced
    - injection cycling – expansion/contraction
    - geochemical alteration (gypsum-anhydrite)
    - gas drying out rock – less likely due to the roof salt, unless it is breached/too thin
- precipitation of cementing materials/bacterialogical activity
    - inside well

D2-253 (Cont.)

- changes to operation characteristics of injection/withdrawal wells – leads to change operating conditions without appropriate precautions/research into effects

Pore storage (depleted oil/gasfield) release scenarios. Will include many of the anticipated scenarios detailed for cavern storage but would also include others, such as:

- Macroseepage mechanisms
  - failure of the old exploration, development and producing well completion(s)
    - between cement and formation/borehole sidewall (rock)
    - between cement & casing
      - outer cement fill
      - well plug
    - through casing
      - fracture/damage
      - corrosion
    - through fractures in outer cement
    - through cement plug
      - fractures
      - diffusion
    - due to damage during maintenance and repair – redrilling of wells
- release of material/gas through leaky interbeds, or nonhomogeneous zones of higher impermeability such as along fault planes
- inadvertent over pressurisation of the storage facility
- failure of the caprock
  - membrane seals
  - hydraulic seals
  - geochemical alteration
    - gypsum-anhydrite
      - input or removal of water to the system
      - Volume change effects – cracks etc to associated interbeds?
    - gas does not generally react chemically with the reservoir or cap rock
    - H_2S – reaction with cement in well completions, both
      - Abandoned wells
      - Working wells
  - injected gas drying out shale caprock
- reactivation of a fault in the cap rock
  - hydraulically induced

D2-253 (Cont.)

- injection cycling – expansion/contraction of the storage unit
- geochemical alteration – volume changes (gypsum-anhydrite??)
- gas drying out rock

- diffusion
  - caprock
  - cement
    - well plug
    - borehole – cement boundary
    - borehole wall – cement boundary
- naturally over pressured layers (rare onshore)
- damage to reservoir formation
  - mechanical - rock structure
  - precipitation of cementing materials/bacterialogical activity
    - closes pore spaces and reduces permeabilities
    - reservoir performance changes around injection/withdrawal wells – leads to change in the operating conditions without appropriate precautions/research into effects
- overfilling (inadvertent)
  - migration away from injection footprint
    - stays in same structure
    - leaks out
      - into adjacent structure (spill point)
      - or out of the structure via
        - faults
        - wells
        - through caprock if overfilling causes overpressuring
        - diffusion – lateral perhaps due to overpressuring driving migration
    - not having fully characterized the storage structure
      - faulting
      - spill point not accurately defined
    - not knowing the volume of gas injected
- failure of the caprock
  - membrane seals
  - hydraulic seals
  - geochemical alteration (e.g. gypsum-anhydrite transition, rock alteration due to interaction with injected gases)
  - gas drying out rock – fracturing/cracking

D2-253 (Cont.)

- reactivation of a fault in the cap rock
  - hydraulically induced
  - injection cycling – expansion/contraction
  - geochemical alteration (gypsum-anhydrite??)
  - gas drying out rock
- knowledge, consideration and modeling of the drive mechanism during production and effects on gas injection pressures and reservoir rock – potential for fracturing
  - gasfields
    - depletion drive
    - water drive – may result in higher injection pressures
    - combination – may result in higher injection pressures
  - oilfields
    - depletion drive
    - water drive – may result in higher injection pressures
    - combination – may result in higher injection pressures
    - residual oil in pore spaces – may result in higher injection pressures than for residual gas in pores for gasfields

Pore storage (aquifer) release scenarios

Aquifers have not previously having held commercial volumes of hydrocarbons and are therefore 'untested'. When compared to converting oil/gasfiels to gas storage, aquifer storage includes a number of unknowns that would require adequate research if such facilities are to be considered in the future. They are not likely to be high on the UK 'agenda' due to increased costs that include determining these uncertainties over the formation and structure. Potential additional risks would incude:

- overpressuring of the aquifer and seal – gas injection requires higher pressures than original in reservoir and
  - to have to displace water from pores
  - area has not previously held hydrocarbons
  - seal has not had to deal with such pressures
- inadvertent over pressurisation of the storage facility
  - damage to seal
  - damage to reservoir
- overfilling (inadvertent)
  - migration away from injection footprint
    - stays in same structure
    - leaks out
      - into adjacent structure (spill point)
      - or out of the structure via
        - faults

D2-253 (Cont.)

        - wells
        - through caprock if overfilling causes overpressuring
        - diffusion – lateral due to structure not having been accurately defined
    - not having fully characterized the structure
        - faulting
        - spill point not accurately defined
    - not knowing the volume of gas injected
- failure of the caprock
    - membrane seals
    - hydraulic seals
    - geochemical alteration (e.g. gypsum-anhydrite transition, rock alteration due to interaction with injected gases)
    - gas drying out rock – leading to fracturing/cracking and potential pathways
- reactivation of a fault in the cap rock
    - hydraulically induced
    - injection cycling – expansion/contraction
    - geochemical alteration (gypsum-anhydrite??)
    - gas drying out rock
- naturally over pressured layers (rare or absent onshore)

D2-253 (Cont.)

Appendix 7 Risk Assessment - parameters for consideration in risk analysis/assessment of UK scenarios

The following represent the general parameters considered during the assessment of potential leakage routes and the construction of modles for the calculation of gas release and flux rates undertaken by Quintessa (Watson et al., 2007).

Depleted oil & gasfields

East Midlands

General geological sequence in areas of main potential:

4 Scenarios:

General dip – gently to east

1. ***Overlain by Chalk (Saltfleetby scenario – Fig. 47)***
    - Upper Cretaceous Chalk – 0-550 m (> 550 m at Saltfleetby)
    - Lower Cretaceous lsts, clays and ssts – c. 35-45 m
    - Upper Jurassic
        - i. Ancholme Clay Group – Kimmeridge Clay, Oxford Clay & Kellaways Beds + West Walton Beds (shelly siltstone) – mainly calcareous and silty mudstones – 75-245 m thick
        - ii. Redbourne Group – Cornbrash (thin = c. 5 m thick)
    - Middle Jurassic – 48-58 m thick
        - i. Redbourne Group – including Great Oolite and Inferior Oolite
            1. mainly limestones and sandstones, including Great Oolite and Inferior Oolite – nearest crop c. 34 km up-dip to west
            2. Lincs Limestone – nearest crop c. 41-41.5 km up-dip to west
                a. Top c. 25 m oolite
    - Lower Jurassic – Lias Group – 130-215m thick
        - i. Mainly mudstones, some ironstones
    - Penarth Group – c. 12-15 m thick
        - i. Mudstones, and interbedded shales and limestones
    - Mercia Mudstone Group – c. 250-300 m thick
        - i. Mainly mudstones
        - ii. Siltones and fine-grained sandstones in part
        - iii. Evaporitic in parts
    - Sherwood Sandstone Group – 300-450 m thick
        - i. Reddish brown sandstones
    - Permian – 215-590 m series of interbedded limestone, mudstone and evaporites
        - i. Staintondale & Eskdale groups – 36-98 m
            1. 4-11 m evaporites including anhydrite
        - ii. Teesside Group – 43-91 m
            1. Boulby Halite (host salt for caverns on Teesside, NE England) – 0-25 m
            2. Billingham Anhydrite – 3-6 m
            3. Brotherton Formation ('Upper Magnesian Limestone') 40-60 m
        - iii. Aislaby Group – 55-160 m

D2-253 (Cont.)

1. Fordon Evaporites (host salt for caverns at Atwick/Hornsea, NE England) – 10-90 m
2. Kirkham Abbey Formation 60-70 m

iv. Don Group – 80-220, but may reach up to 270 m in east
1. Hayton Anhydrite 65-150 m, thinning southwestwards
2. Cadeby Formation 8-15 m
3. Marl Slate 2-3 m

v. Basal Permian sands – 10-40 m

- Carboniferous - > 740 m
  i. Coal Measures – 495-740 m
     1. Upper Coal Measures – 0-175 m thick
     2. Middle Coal Measures – 275-330 m thick
     3. Lower Coal Measures – 220-236 m
  ii. Millstone Grit (Namurian) – up to 247 m proved (c. 25 m at Saltfleetby)
  iii. Dinantian – limestones >10 m
- Faulting
  i. Some at reservoir level and Westphalian and pre Upper Magnesian Limestone (Permian)
     1. up to 100m displacement
     2. 20-60 m average displacement
  ii. Minor in overburden (below seismic resolution) and not penetrating to reservoir level
  iii. None to surface (none mapped and/or below seismic/mapping resolution)
- Main gas storage reservoir – late Westphalian B 'Oaks Rock Sandstone' at c. 425 m below Ordance Datum (OD) in crest of anticlinal trap
  i. Area of gasfield = 2857 acres
  ii. 7.6-27.4 m thick
  iii. Porosity – 9.5-12.5%
  iv. Permeability – 1-10 mD
  v. Original reservoir pressure – c. 3566 psig (24.6 MPa or 246 bar)
- Borehole density – 18 exploration/development wells to the reservoir horizon, including horizontal wells
  i. 11 km square – circa 642
     1. 67 greater than 50 m
     2. 24 greater than 100 m
     3. 574 less than 50 m
     4. 618 less than 100 m
  ii. 3 km buffer – circa 482 boreholes in 81 km^2
     1. 44 greater than 50 m
     2. 23 greater than 100 m
     3. 400 less than 50 m
     4. 458 less than 100 m
  iii. 1 km buffer – 206 boreholes in 42 km^2
     1. 23 greater than 50 m
     2. 19 greater than 100 m
     3. 183 less than 50 m
     4. 187 less than 100 m
- Series of basal Westphalian channel sands
  i. Deposited in a major fluvio-deltaic system across much of northern England, giving general ascending sequence
     1. Pro-delta submarine fans – isolated sandstone bodies within mudstone dominated sequences
     2. Delta front deposits – feeder channels to the submarine fans

D2-253 (Cont.)

3. Lower delta plain channels -
4. Upper delta plain

- Fields within 3 km – 1 (Keddington Oilfield)
- Nearest major town/city – Louth c. 6.5 kms to WSW, Grimsby c. 18 kms to NNW

2. Chalk absent at crop (Welton scenario – Fig. 48) – Jurassic or Triassic

- General dip - gently dip to east
- Jurassic (at crop)
  - i. Upper Jurassic
    1. Ancholme Clay Group –
       a. Oxford Clay – thin or absent
       b. Kellaways Formation – c. 16 m thick
    2. Redbourne Group - Cornbrash (limestone – thin c. 5 m thick)
  - ii. Middle Jurassic
    1. Redbourne Group - including Great Oolite and Inferior Oolite
       a. Blisworth Clay – c. 7 m thick
       b. Blisworth Limestone – 8-9 m thick
       c. Rutland Formation (Upper Estuarine Series) – 6 m thick
       d. Lincs Limestone Formation – c. 50 m – nearest crop c. 6.8 km to west
       e. Top 25 m oolite
  - iii. Lower Jurassic – Lias Group – 195-200 m thick
    1. Middle Lias Marlstone Rock – c. 3 m thick (110-113 m)
    2. Hydraulic Limestone at base c. 6 m thick (290-296 m)
- Triassic – *nearest crop to field 17.5-18 km to west*
  - i. Penarth Group – c. 13 m thick
  - ii. Mercia Mudstone Group – c. 280 m thick (319-599 m) - *17.5-18 km to west*
  - iii. Sherwood Sandstone Group – c. 260 m (599-860 m) thick
- Permian –
  - i. Upper Marls – 57 m thick
  - ii. Brotherton Formation ('Upper Magnesian Limestone') – c. 27 m thick
  - iii. Middle Marl – c. 43 m thick
  - iv. Cadeby Formation ('Lower Magnesian Limestone') – c. 16 m thick
  - v. Lower Marl – c. 46 m thick
  - vi. Basal Sand – c. 25 m thick
- Carboniferous – c. 540 m (1074-1616 m approx.)
  - i. Upper Coal Measures – c. 170 m thick
  - ii. Middle Coal Measures - c. 165 m thick
  - iii. Lower Coal Measures – c. 209 m thick
  - iv. Late Namurian/early Westphalian – 22-90 m (1616-1638 m in B3)
  - v. Dinantian – c. 12 m
- Reservoir – series of switching, low sinuosity fluvio-deltaic channels and associated overbank environments – perhaps 3 different units at Welton (Rothwell & Quinn, 1987). However, Star Energy have reinterpreted the sandstones and their depositional environment (submitted in their application to Lincolnshire County Council to convert Welton to gas storage facility)
  - i. IV = 5-21 m (porosity 9-21%; permeability 5-100 mD)
  - ii. III = 10-23 m (porosity 9-22%; permeability 10-500 mD)
  - iii. I = 7-57 m (porosity 9-21%; permeability 1-30 mD)
  - iv. Original reservoir pressure – 2230 psig (15.4 MPa or 154 bar)
- Oil gravity/density - 36° API
- Faulting

D2-253 (Cont.)

i. Some of reservoir and Westphalian and pre Upper Magnesian Limestone (Permian)
ii. Some of overburden, but not penetrating to reservoir level
iii. None to surface (mapped and/or below seismic/mapping resolution)

- Borehole density – ≥54 exploration/development wells, majority being from 3 well sites/platforms
  i. 11 km square – circa 642
     1. 81 greater than 50 m
     2. 60 greater than 100 m
     3. 555 less than 50 m
     4. 575 less than 100 m
  ii. 3 km buffer – circa 468 in 3 km buffer = c. 63 km^2
     1. 76 greater than 50 m
     2. 59 greater than 100 m
     3. 406 less than 50 m
     4. 423 less than 100 m
  iii. 1 km buffer – 210 boreholes in 30 km^2
     1. 67 greater than 50 m
     2. 54 greater than 100 m
     3. 157 less than 50 m
     4. 170 less than 100 m
- Fields within 3 km – 3
- Nearest major town/city – Lincoln c. 5.5-6 kms to west
- Water injection has supported production since 1986/7

3. Chalk absent at crop (Gainsborough-Beckingham scenario – Fig. 49)

- Drift – c. < 10 m thick
- Jurassic – thin in most easterly areas (< 20 m thick) or (mostly) absent at crop
- Triassic – c. 480 m (eroded thickness in west)-550 m thick in east
  i. Mercia Mudstone Group – at crop over majority of the field – c. 170-270 m thick
  ii. Sherwood Sandstone Group – nearest crop = 4 km to west – c. 280 m thick
- Permian – c. 225-250 m thick
  i. Upper Marls –c. 43 m thick
  ii. Brotherton Formation ('Upper Magnesian Limestone') – c. 24 m thick
  iii. Middle Marl – c. 39 m thick
  iv. Cadeby Formation ('Lower Magnesian Limestone') – c. 76 m thick
  v. Lower Marl – c. 50 m thick
  vi. Basal Sand – c. 10-15 m thick
- Westphalian – c. 640-675 m thick
  i. Series of coals, mudstones and sandstones
- Namurian – c. > 70 m thick
- Faulting
  i. Some of reservoir and Westphalian and pre Permian
  ii. None to surface at oilfield (mapped and/or below seismic/mapping resolution)
  iii. Nearest mapped at crop on east edge of Sherwood Sandstone Group – 1.7-4.5 km away
- Reservoirs –
  i. Main = series of basal Westphalian channel sands – c. < 40-45 m thick
  ii. Other

D2-253 (Cont.)

1. (younger) minor channel sands in Coal Measures sequence
2. late Namurian sandstones

- Porosity – c. 15 % (Egmanton data)
- Permeability – 1-10 (av. 3) mD (Egmanton data)
- Original reservoir pressure – c. 1400 psi (9.7 MPa or 97 bar)
- Oil gravity/density – 35.64° API
- Borehole density –
  i. 11 km square – circa 560 – though unrepresentative totals – depth not assigned in database – 156 boreholes
     1. 154 greater than 50 m
     2. 152 greater than 100 m
     3. 400 less than 50 m
     4. 405 less than 100 m
  ii. 3 km buffer – circa 553 in 3 km buffer = c. 140 km^2 – though unrepresentative totals – depth not assigned in borehole database – c. 155 boreholes
     1. 151 greater than 50 m
     2. 149 greater than 100 m
     3. 398 less than 50 m
     4. 400 less than 100 m
  iii. 1 km buffer – 362 boreholes in 50 km^2 - slightly unrepresentative totals – depth not assigned in database –c. 96 boreholes
     1. 150 greater than 50 m
     2. 148 greater than 100 m
     3. 212 less than 50 m
     4. 214 less than 100 m
- Fields within 3 km – Gainsborough-Beckingham Oilfield - series of closely associated structures, although connectivity between one or more is not known
- Nearest major town/city – Gainsborough – developed above the oilfield

Hatfield Moors scenario – note, at Hatfield Moors storage facility, reservoir is at 425 m below OD:

- Drift – c. < 10 m thick
- Triassic - > 245 m thick
- Sherwood Sandstone Group - > 245 m thick
- Permian – c. 170-175 m thick
  - Upper Marls –c. 37 m thick
  - Brotherton Formation ('Upper Magnesian Limestone') – c. 20 m thick
  - Middle Marl – c. 45 m thick
  - Cadeby Formation ('Lower Magnesian Limestone') – c. 50 m thick
  - Lower Marl – c. 1.5-5 m thick
  - Basal Sand – may be absent
- Westphalian – c. 705 m thick
  - Series of coals, mudstones and sandstones
  - Main reservoir – Oaks Rock Sst – c. 425 m below OD
    - Channel sands in braided stream environment, being typically between 3 m and <10 m deep
    - Fluvial system around 5-10 km wide flowing to SW
- Namurian – c. > 710 m thick
- Faulting
  - Some at reservoir and Westphalian and pre Permian levels

D2-253 (Cont.)

        - Mapped at surface at oilfield (NW-SE) and in subsurface from seismic reflection data (mainly NE-SW)
            - Hatfield Fault (NE-SW) - downthrow circa 25-60 m
- Trap – tilted anticlinal fault block
- Main gas storage reservoir – late Westphalian B 'Oaks Rock Sandstone' at c. 425 m below OD in crest of anticlinal trap
    - 7.6-27.4 m thick
    - Porosity – 17.2-25.6%
    - Permeability – 21-1100 mD
    - Original reservoir pressure – c. 650 psi (4.5 MPa or 45 bar), c.600 psi in Hatfield West (Ward et al., 2003)
- General Westphalian channel dimension data for the East Midalnds oil province - refer Figs 13&14 and Appendix 3
- Borehole density - ≥6 exploration and development wells to reservoir horizon
    i. 11 km square – circa 756
        1. 37 greater than 50 m
        2. 26 greater than 100 m
        3. 719 less than 50 m
        4. 730 less than 100 m
    ii. 3 km buffer – circa 600 in 3 km buffer = c. 99 km^2
        1. 34 greater than 50 m
        2. 24 greater than 100 m
        3. 566 less than 50 m
        4. 576 less than 100 m
    iii. 1 km buffer – 144 boreholes in 30 km^2
        1. 12 greater than 50 m
        2. 7 greater than 100 m
        3. 132 less than 50 m
        4. 137 less than 100 m
- Fields within 3 km – 1 (Hatfield West), accumulations separated by NE-SW Hatfield Fault
- Nearest major town/city – Doncaster – c. 5 kms to W

Westphalian sandbodies – dimensions and depositional setting in the southern North Sea, eastern and northern England

A major depositional basin, the Pennine Basin, existed in Britain during Silesian times (Namurian and Westphalian), formed as a result of major crustal rifting processes in mainly Dinantian and early Namurian times. The Pennine Basin, within which a number of smaller sub basins were formed, lay to the north of the Wales–Brabant Massif and extended northwards towards the Southern Uplands of Scotland (Guion & Fielding, 1988; Collinson, 1988; Martinsen et al., 1995) and was gradually filled by enormous volumes of siliciclastic sediment (sandstones, conglomerates, siltstones, mudstones) and coals, which now form the Westphalian Coal Measures. The dominant source of this sediment, supplying by far the greatest volumes to the area throughout the Carboniferous, lay to the north. The SNS basin represented the eastern extension of this major depocentre to which several sources supplied sediment with a diminishing number of channels penetrating the basin centre with time. The sediment patterns indicate that sediment was introduced to the onshore UK coalfield areas from a northerly source lying to the north of the concealed and residually buoyant Market Weighton Block, and through quite a narrow major channel feeder route located in the region of the present day Humber (Collinson et al., 1993). Some sediment was locally derived and supplied to the basin from the London Brabant Massif to the south in a narrow strip along the southern margin of the basin.

D2-253 (Cont.)

Many studies have been published on Westphalian channel dimensions, but these tend to be specific papers dealing with specific channels. Fewer papers (e.g. Guion & Fielding, 1988; Collinson et al., 1993; Rippon, 1996) deal with the broader picture. In general, Westphalian sediments onshore in the UK were deposited across virtually the entire basin in a broad flat delta plain environment (see e.g. Fielding, 1984). Initial sedimentation in early Westphalian A times took place in a shallow water delta/lower delta plain setting (Fig. 14), where delta lobes built out across the basin into a body of water 10-50 m deep. The deltas were fed by major low sinuosity distributary channel belts across the lower delta plain area and delta fronts were wave-influenced, locally, having been reworked to form elongate shoreline deposits after abandonment of the delta lobes. Major distributary channels were the main pathway of sediment dispersal across the delta plain and these fed a hierachy of low energy, low gradient minor distributary channels and crevasse (splay) systems, depositing sediment in shallow lakes. Major distributary channels deposited elongate sand bodies, whilst interdistributary bays and lakes were infilled by crevasse splays/deltas and overbank deposits (Guion & Fielding, 1988). During Westphalian A times, the lower delta plain /shallow water delta environment gradually changed such that by mid Westphalian A times, the majority of sedimentation across the basin was in an upper delta plain environment that continued to Upper Westphalian B times (Guion & Fielding, 1988). In late Westphalian B times there was probably a brief return to lower delta plain environments. This change from lower to upper delta plain environment is reflected in the upward transition from broad, coarse-grained, low sinuosity channel belts to more sinuous, narrow, finer-grained major distributary channels.

As alluded to, the majority of the Westphalian A and B rocks were deposited in an upper delta plain environment, generally isolated from marine processes. Major distributary channels of variable sinuosity forming sandy channel belts mostly up to 5 km wide, were the main pathway for sediment dispersal (Fielding, 1984, 1986; Guion & Fielding, 1988). There was regular switching of major distributaries, often within narrow belts. Channel dimensions are described in more detail in section 5.2.3.2.

Within the Westphalian sequences, the vast majority of sandstone channels are of fluvial origin (deposited in a large river system). A study of Carboniferous sequences in wells both onshore and offshore in the SNS reveals (Fig. 13) that the thickest channel sandstone bodies (35-40 m) are over 10 km wide, whilst most of the thinner sandstone bodies (<10 m) are likely to have widths of 100 m or less (Collinson et al., 1993; Guion et al., 1995; Aitken et al., 1999). It is perhaps significant that almost all of the sandbodies over 20 m in thickness were thought to have been deposited as multi storey units. As indicated above, the Westphalian A succession is sandstone rich, whilst the Westphalian B is a relatively sand-poor interval. Sandstone channel thicknesses increase again in Westphalian C/D times. Very often channel sandstone architecture indicates broader channels in early Wesphalian A times, becoming with time narrower and stacked either vertically or diagonally, during late Wesphalian A and B times. The presence of such thicker and elongate sand bodies parallel to faults indicates some sort of structural control on the location of the channels that were funnelled into structural lows across the delta plain (Fielding, 1984).

Within many stratigraphic intervals, channel sandbodies show gradual reductions in thickness across three domains. This represents a passage not only outwards from the sedimentation (channel belt) axis, but also from north to south as lesser volumes of sediment were transported to more distal areas at the delta front. In such areas the gradient was lower and the channel systems split into distributary networks of smaller channels of decreasing size. Clearly, sedimentation/channel axes were controlled by underlying structures. Where an increase in the proportion of individual channels sandbodies in the sequence occurs, this can lead to an increase in the probability of stacking, the creation of multi storey sandbodies and thus greater thicknesses of sandstone (Bridge & Leeder, 1979; Collinson et al., 1993). Within the depositional systems, systematic downstream changes of channel dimensions are the result of the existence of distributary channel networks across the delta.

D2-253 (Cont.)

A relationship exists between channel width and thickness (Fig 13), with the maximum width being around 30 km and maximum thickness being 40-50 m (but up to 100 m where sandbodies are amalgamated). Additionally, the data illustrate that 90% of channel sandbodies are less than 25 km wide and less than 40 m thick and that generally, reservoir intervals greater than 30 m will extend for more than 10 km perpendicular to the palaeoflow direction (Aitken et al., 1999). There is also a 35% probability of penetrating a relatively poor reservoir zone within the main channel belt, due to fine grained horizons interpreted to be partial abandonment channel reaches. By their nature and origin, these are difficult to correlate and may form potential baffles of up to several hundred metres in extent within the channel sandstone reservoirs.

Channel sandstones comprising the late Westphalian B Oaks Rock reservoir in the Hatfield Moors gas storage facility have been cored extensively and channel parameters deduced (Ward et al., 2003). Typically, the Oaks Rock reservoir thickness is between 14 m and 26 m thick, with individual channel sands indicate that internal channels were < 10 m deep and more generally around 3 m deep. From outcrop work on Upper Carboniferous (Namurian and Westphalian) sequences (Aitken et al., 1999; Hampson et al., 1999), these dimensions would suggest an overall channel thickness of around 30 m and a width of 5-10 km (Ward et al., 2003).

Westphalian channel settings and sizes are summarised in Fielding (1984), Guion et al. (1995) and Aitken et al. (1999) and are (Fig. 14):

- proximal/lacustrine delta – 1-10 km wide with lobate to sheet-like deposits generally < 8 m thick.
- Major channels – 10's kilometres long, 1-20 km wide and typically 8-20 m thick
- Minor channels – up to 10 kilometre long, 10-1 km wide and typically 1-8 m thick
- Overbank deposits – elongate belts parallel to channels. Dimensions depend upon channel sizes, typically 1-8 m thick and 10's m wide
- Crevasse splay – minor delta developments along main channel resulting from overbank flow. Circa 1 km wide and 0-1 m thick, thinning away from channel centre

NE England

1. General geological sequence in areas of main potential *Caythorpe* scenario (Fig. 50):
   - Upper Cretaceous Chalk – c. 225-230 m thick
   - Lower Cretaceous - c. 21 m
   - Jurassic
     - Kimmeridge Clay – c. 310-415 m thick
     - Corallian – c. 50-65 m thick
     - Kellaways & Estuarine series – 275-285 m thick
     - Lias Group – 120-205 m
   - Triassic – 485-700 m thick
     - Penarth group – c. 6-7 m thick
     - Mercia Mudstone Group – c. 30-280 m thick
     - Sherwood Sandstone Group – c. 145-324 m thick
   - Permian – total 500-525 m thick
     - Staintondale & Eskdale groups (Upper marls, anhydrites & halites) – c. 35-95 m thick
     - Brotherton Formation ('Upper Magnesian Limestone') – c. 40-75 m thick
     - Middle Marls, anhydrites & halites – c. 92-440 m thick
     - Cadeby Formation ('Lower Magnesian Limestone') – c. 10-15 m thick

D2-253 (Cont.)

        - Lower Marl – c. 3-5 m thick
        - Basal Sand (Upper Rotliegend) – c. 18-35 m thick
    - Carboniferous (Westphallian 'A') – > 153 m
- Faulting –
    - Close to E-W trending Vale of Pickering-Flamborough Head Fault Zone (Kirby & Swallow, 1987)
        - Likely at reservoir level
        - Some apparent in the Chalk and to surface
    - Present in one borehole faulting Sherwood Sandstone Group against late Zechstein at c. 1672 m depth
    - Appear to stop at base Chalk on seismic reflection data – but may be present as sub seismic resolution faults in the field
- Borehole density – minimum of 2 exploration/development wells (C-1 & C-2) to the reservoir horizon. C-2 deviated strongly (42°) to west of C-1
        - 11 km square – circa 168
            - 33 greater than 50 m
            - 3 greater than 100 m
            - 132 less than 50 m
            - 162 less than 100 m
        - 3 km buffer – circa 68 boreholes in 56 km^2
            - 15 greater than 50 m
            - 3 greater than 100 m
            - 52 less than 50 m
            - 64 less than 100 m
        - 1 km buffer – 13 boreholes in 42 km^2
            - 2 greater than 50 m
            - 2 greater than 100 m
            - 11 less than 50 m
            - 11 less than 100 m
- Reservoir(s)
    - Kirkham Abbey Formation – (dolomitic) oolitic lsts - shelf deposits – from c. 1748 m - 2090 m depth
        - Porosity – average porosity of 15% (IEA, 1999), mainly network of fine fractures and vuggy dolomitic porosity
        - Permeability - bulk rock low – may be fissure dominated
        - Average water saturation of 40%
        - Original reservoir pressure - 2,835 psia (19.6 MPa or 196 bar)
        - Gas had an H_2S content of around 5 parts per million (ppm)
        - Tested for 30 hours in well C-2 at up to 8 Million Standard Cubic Feet per Day (MMscfd) from a 13 m
    - Early Permian Rotliegend (Leman Sandstone equivalent) sands? – c. 1829 m - 2135 m depth
        - Environment of deposition – regionally extensive basin margin deposits and representing dune sands
        - 2 sections to reservoir interval –
            - upper – best properties c. 100 mD. On extended test from a 3 m interval near the top of the reservoir tested at rates up to 10 MMscfd
            - lower – less favourable properties c. 20 mD. Tested at 1.0 MMscfd for 4 hours from a 3 m interval
        - Porosity – av 18 % (10-24 for Southern North Sea fields)
        - Permeability – 20-100 mD (1-1000, av 30 mD for Southern North Sea fields)

D2-253 (Cont.)

- Average water saturation of 31%
- Original reservoir pressure – 2,969 psia (20.5 MPa or 205 bar)
- Gas production form Rotliegend reservoir(s) only (IEA, 1999)
- Rotliegend gas has no reported H_2S content
- mapped closure is approximately 213 acres for the Rotliegend

- Fields within 3 km - none

2. General geological sequence in areas of main potential *Kirby Misperton-Marishes* scenario (Fig. 50):

- Upper Cretaceous Chalk – absent, but present at crop c. 4-11.5 km to SE
- Lower Cretaceous - absent, but present at crop c. 4-11.5 km to SE
- Jurassic – total thickness c. 630-935 m
  - Kimmeridge Clay – at crop c. 85-300 m thick
  - Corallian – c. 15-50 m thick
  - Oxford Clay – c. 50-55 m thick
  - Kellaways & Estuarine Series – c. 120-190 m thick
  - Lias Group – c. 60-380 m
- Triassic – c. 325-465 m thick
  - Penarth Group – c. 10 m thick
  - Mercia Mudstone Group – c. 160-190 m thick
  - Sherwood Sandstone Group – c. 150-265 m thick
- Permian – total c. 375-430 m thick
    - Upper marls, anhydrites & halites – c. 60-70 m thick
    - Upper Magnesian Limestone – c. 15-27 m thick
    - Middle Marls, anhydrites & halites – c. 290-330 m thick
    - Lower Magnesian Limestone – c. 25-35 m thick
    - Lower Marl – c. 3-5 m thick
    - Basal Sand – c. 3-5 m thick
- Carboniferous (Namurian) – > 125 m
- Faulting –
  - Close to E-W trending Vale of Pickering-Flamborough Head Fault Zone (Kirby & Swallow, 1987) – faults mapped at crop c. 2.5-6 km to south
    - Likely at reservoir level
    - Present at crop faulting Kimmeridge Clay against limestones of the Corallian Group – c. 10-50 m throw.
  - Mapped at surface
- Borehole density – 2 to 3 exploration/development wells to reservoir horizon
  - 11 km square – c. 178
    - 33 greater than 50 m
    - 3 greater than 100 m
    - 132 less than 50 m
    - 162 less than 100 m
  - 3 km buffer – circa 100 boreholes in 63 km^2
    - 10 greater than 50 m
    - 9 greater than 100 m
    - 89 less than 50 m
    - 90 less than 100 m
  - 1 km buffer – 20 boreholes in 42 km^2
    - 5 greater than 50 m
    - 4 greater than 100 m
    - 15 less than 50 m
    - 16 less than 100 m

D2-253 (Cont.)

- Reservoir(s)
  - Kirkham Abbey Fm - (dolomitic) oolitic lsts shelf deposits
    - Porosity - low (< 5%), mainly network of fine fractures and vuggy dolomitic porosity
    - Permeability - bulk rock low - fissure dominated?
    - Original reservoir pressure – not available
    - Depth c. 1556 m below OD
  - Early Permian Rotliegend (Leman equiv.) sands secondary reservoir?
    - Environment of deposition – basin margin deposits = dune sands
    - Porosity – 10-24 (av 15) % (based upon Southern N Sea fields)
    - Permeability – 1-1000 (av 30) mD based upon Southern N Sea fields)
    - Depth c. 1591 m below OD
    - Original reservoir pressure – not known
  - Namurian clastic delta (Fraser & Gawthorpe, 2003) – Follifoot Grits, but little information available
    - Depth c. 1593 m below OD
- Fields within 3 km – 1
- Nearest major town/city – Bridlington c. 5 kms to E

Southern Britain

Humbly Grove scenario scenario – northern Weald Basin – Figs 51&52

General geological sequence in areas of main potential:

- One of a cluster of 4 closures and associated fields
- Main reservoir - Great Oolite Limestone (Bathonian; Middle Jurassic) - 2 distinct upper and lower units separated by permeability barrier
- Original reservoir pressure – 1480 psi (10.2 MPa or 102 bar)
- Porosity – av. 18%, range 6-28%
- Permeability - 20-2000 mD (zone 1) and 0.5-2 mD (zone 2)
- Oil gravity/density - 39° API
- Faulting – E-W trending horst block, fault bounded to north and south
- Faults affect
  - Reservoir and caprock sequences
  - Appear to stop at base Chalk but may be present as sub seismic resolution faults in the field
- Borehole density - ≥13 deviated wells drilled between Mar 1985 & May 1986 from 3 sites, 3 others (2 horizontal from existing wells) between 1994-1996. Further wells drilled for conversion to gas storage between 2003-05
  - 11 km distance – circa 2200
    - 230 greater than 50 m
    - 95 greater than 100 m
    - 2058 less than 50 m
    - 2190 less than 100 m
  - 3 km buffer – circa 264 boreholes in 170 km^2
    - 67 greater than 50 m
    - 32 greater than 100 m
    - 197 less than 50 m
    - 230 less than 100 m
  - 1 km buffer – 65 boreholes in 65 km^2
    - 33 greater than 50 m
    - 20 greater than 100 m

D2-253 (Cont.)

- 32 less than 50 m
- 44 less than 100 m

- Fields within 3 km – 2 = satellite structure (Herriard and Hesters Copse)
- Nearest major town/city – Basingstoke (4 km to NW), Aldershot (10 km) and Guildford (20 km) to E

Storrington scenario – southern Weald Basin – Fig. 51

- Cretaceous –
  - U Cretaceous Chalk – thin or absent at crop
  - Lower Cretaceous – c. 486 m thick
    - Lower Greensand – c. 35 m thick
    - Weald Clay – c. 195-200 m thick
    - Wealden Group – c. 250-440 m thick
      - Incl. Weald Clay – c. 195-200 m thick
  - Jurassic – c. 1500 m
    - Purbeck – c. 175 m
    - Portland – c. 44 m
    - Kimmeridge Clay – c. 394 m
    - Corallian – c. 143 m
    - Oxford Clay – c. 153 m
    - Kellaways Beds – c. 14 m
    - Great Oolite Group – c. 86 m
    - Fullers Earth – c. 59 m
    - Inferior Oolite – c. 228 m
    - Lias – c. 215 m
  - Triassic - > 105 m
    - Penarth Group – c. 14 m
    - Mercia Mudstone Group - > 91 m
- Trap – northerly tilted fault block – down-south fault defines southern margin of field – c. 45-50 m throw
- Faults affect reservoir and (Jurassic) caprock sequences
- Reservoir – Great Oolite Group (Middle Jurassic)
- Original reservoir pressure – 1758 psi (12.1 MPa or 121 bar)
- Porosity – av. 13%, range 6-26%
- Permeability – av. 5, range 0.1-2000 mD
- Oil gravity/density – 39.04° API
- Borehole density – ≥6 exploration and development wells
  - 11 km distance – circa 527
    - 103 greater than 50 m
    - 31 greater than 100 m
    - 426 less than 50 m
    - 499 less than 100 m
  - 3 km buffer – circa 339 boreholes in 88 km^2
    - 65 greater than 50 m
    - 18 greater than 100 m
    - 276 less than 50 m
    - 325 less than 100 m
  - 1 km buffer – 48 boreholes in 24 km^2
    - 10 greater than 50 m
    - 6 greater than 100 m
    - 42 less than 50 m
    - 46 less than 100 m

D2-253 (Cont.)

- Fields within 3 km – none
- Nearest major town/city – Chichester c. 17 km to SW, Horsham c. 14.5 km to NE

NW England

Elswick gasfield scenario – Fig. 53

General geological sequence in areas of main potential:

- Triassic
  - Mercia Mudstone Group – c. 320 m
  - Sherwood Sandstone Group
    - Above silicified zone – c. 315-320 m
    - Below silicified zone – c. 205-210 m
- Permian
  - Manchester Marls – 190-195 m
  - Collyhurst Sandstone (reservoir; IEA, 1999) – c. 550-560 m (at c. 1015 m BOD)
    - Porosity – c. 5.6%
    - Permeability - < 1 mD
    - Water saturation – c. 60%
    - Reservoir stimulation undertaken in 1993 - retested for 80 hours at 0.2 MMscfd from a 29 m interval.
- Carboniferous - > 20 m
- Faulting/Structure
  - Faulted anticline in graben bounded by two N-S faults
  - Faults mapped at surface affecting Mercia Mudstone Group - however, area heavily drift covered and actual surface locations may be subject to revision
  - Area of closure circa 997 acres (IEA, 1999)
  - intragrabenal faulting in crestal area (1-3 km^2) – penetrate reservoir and to surface
- Borehole density – at least 1 exploration and development well to reservoir horizon
    - 11 km buffer – circa 280 boreholes
      - 18 greater than 50 m
      - 13 greater than 100 m
      - 262 less than 50 m
      - 267 less than 100 m
    - 3 km buffer – circa 84 boreholes in 72 km^2
      - 9 greater than 50 m
      - 7 greater than 100 m
      - 75 less than 50 m
      - 77 less than 100 m
    - 1 km buffer – 65 boreholes in 20 km^2
      - 2 greater than 50 m
      - 2 greater than 100 m
      - 13 less than 50 m
      - 13 less than 100 m
- Reservoir – Permian Collyhurst Sandstone – often conglomeritic and pebbly, generally tight (IEA, 1999), top mapped at around 1015 m BOD (IEA, 1999)
- Original reservoir pressure – 1685 psia
- Fields within 3 km – none
- Nearest major town/city – Blackpool c. 6 km to W, Kirkham c. 2.5 km to S, Preston c. 10 km to SE

D2-253 (Cont.)

Salt cavern scenarios

Cheshire Basin (Fig. 54)

General geological sequence in areas of main potential:

- Drift – variable and often thick (c. <5-92 m, averaging 20-45 m thick), with rockhead in places below sea level and known to be between 30 and 60 m below sea level in some areas. Includes:
  - Alluvial – river and estuarine alluvium
  - peat
  - glacial
    - boulder clay
    - sand, gravel and laminated clays
- Jurassic
  - Calcareous Liassic mudstones – up to 130 m thick
  - only present in southern Cheshire Basin around Wem, **Jurassic not present in North around Byley**
- Mercia Mudstone Group
  - Brooks Mill Mudstone Formation – variable thickness preserved and not present in the north around Byley developments
  - Wilkesley Halite Member – variable thickness (up to c. 100m) and variably affected by wet rockhead conditions – sometimes represented by collapse breccia
  - Wych Byley Mudstone members – up to 580 m thick.
    - Tight silty claystone
    - Some halite as recrystallised 'clusters'
    - King Street Fault intersected in the mudstones by boreholes drilled in 1980s. Fault plane found to (Buetal, 2002):
      - cause no loss of drilling mud circulation
      - no indication of the fault in behaviour of the drilling equipment
      - be indistinguishable from adjacent (country) rock
  - Northwich Halite Member – up to 290 m thick
    - Intermittent marl (mudstone) and salt-bearing marl interbeds
    - Up to 10.8 m thick ('30 Foot' Marl)
    - Typically contain a certain amount of swelling clays
  - Bollin Mudstone Member – 260-460 m thick
    - Tight silty claystone
    - Some halite as recrystallised 'clusters'
  - Tarporley Siltstone Formation – approximately 20-250 m thick
- Sherwood Sandstone Group
  - Helsby Sandstone Formation – approximately 20-200 m thick
  - Wilmslow Sandstone Formation – c. 200-425 m thick
- Wet Rockhead (refer Fig. 11) – variable but extends from around 60 m to 122-155 m, extreme local incidents of perhaps 180 m are reported (Howell, 1984; Cooper, 2002)
  - 'Brine runs' and subsidence features –
    - Linear and branching
      - 0.5-1.5 km long
      - 7.5-10 m deep
      - 65-75 m wide
    - Circular/crater
- Faulting

D2-253 (Cont.)

- Down-west Wem-Red Rock basin bounding fault to east (c. 14.5-17 km)
- Down-east King Street Fault to west (c. 0.5-2 km)
- Little other faulting known in proposed area

- Borehole density (based upon Byley – but likely to be unrepresentative – depth not assigned in database – 103 confidential ICI boreholes at Holford Brinefield; depth likely to be >100 m)
  - 11 km distance – 1438 boreholes (unrepresentative – depth not assigned in database – 103 confidential ICI boreholes at Holford Brinefield; depth likely to be >100 m)
    - 74 greater than 50 m (unrepresentative – depth not assigned in database – 103 confidential ICI boreholes at Holford Brinefield; depth likely to be >100 m)
    - 29 greater than 100 m (unrepresentative – depth not assigned in database – 103 confidential ICI boreholes at Holford Brinefield; depth likely to be >100 m)
    - 1364 less than 50 m - unrepresentative due to confidential boreholes
    - 1408 less than 100 m - unrepresentative due to confidential boreholes
  - 5 km buffer – circa 794 boreholes in 81 km^2
    - 22 greater than 50 m (unrepresentative – depth not assigned in database – 102 confidential ICI boreholes at Holford Brinefield; depth likely to be >100 m)
    - 12 greater than 100 m (unrepresentative – depth not assigned in database – 102 confidential ICI boreholes at Holford Brinefield; depth likely to be >100 m)
    - 772 less than 50 m
    - 781 less than 100 m
  - 3 km buffer – circa 247 boreholes in 36 km^2
    - 3 greater than 50 m (unrepresentative – depth not assigned in database – 102 confidential ICI boreholes at Holford Brinefield; depth likely to be >100 m)
    - 3 greater than 100 m (unrepresentative – depth not assigned in database – 102 confidential ICI boreholes at Holford Brinefield; depth likely to be >100 m)
    - 3 less than 50 m - unrepresentative due to confidential boreholes
    - 3 less than 100 m - unrepresentative due to confidential boreholes
  - 1 km buffer – 2 boreholes in 1 km^2
    - 0 greater than 50 m
    - 0 greater than 100 m
    - 2 less than 50 m
    - 2 less than 100 m
- Oil/gasfields within 3 km – none
- Other salt cavern facilities within 3 km – 1 operational, 2 planned
- Nearest major town/city – Northwich (NW), Winsford (SW) & Middlewich (S) c. 0.5-7 km from general area of proposed sites

Byley (Beutal, 2002) – Figs 54&55:

- c. 2.5 km south of Holford Brinefield caverns
- Eight caverns in Northwich Halite
- Depths of between 630-730 m below ground level
- Up to 180 m of salt above top of caverns

D2-253 (Cont.)

- Maximum cavern height 100 m
- Maximum cavern diameter 90 m
- Operating pressures of between 35 and 105 bar (3.5/10.5 MPa or 508/1523 psi)
- Spacing between wellheads – 280 m
- 300 m or more of Triassic Bollin Mudstone below the Northwich Halite
- Contains compacted intermittent marls, including 30 Foot Marl in lower third of salt sequence (Figs 54&55)
- Marl beds in salt
    - Not soluble
    - become soft, crumble and fall down to base of cavern during solution mining
- no indications of wet rockhead conditions within 1.5 kms
- King Street Fault – no evidence for water circulation or connection between differing structural levels

Holford

- Same geological conditions as per Byley, but taking into account the different depths to Northwich Halite
- Cavern depths c. 370-440 m below ground level

Stublach:

- 2 kms from Byley site
- Same geological conditions as per Byley, but taking into account the different depths to Northwich Halite
- Caverns in Northwich Halite
- Bell shaped
- About 100 m in height
- Top of caverns c. 500-550 m below ground
- 28 caverns in a 475 hectare (4.75 km^2) site

Nearest major town/city to Byley, Holford and Stublach facilities - Northwich (NW), Winsford (SW) & Middlewich (S) c. 0.5-7 km from general area of proposed sites

Hole House (Fig. 55) – Warmingham Brinefield

- Same geological conditions as per Byley, but taking into account the different depths to Northwich Halite
- Cavern depths c. 300-400 m below ground level
- Faulting – down-east King Street Fault to east c. 1 km
- Borehole density – Warmingham saltfield close by – c. 0.5 km to east
    - 11 km distance – c. 655
        - 56 greater than 50 m (unrepresentative – depth not assigned in database – confidential ICI boreholes at Warmingham Brinefield; depth likely to be >100 m)
        - 42 greater than 100 m (unrepresentative – depth not assigned in database –confidential ICI boreholes at Warmingham Brinefield; depth likely to be >100 m)
        - 598 less than 50 m - unrepresentative due to confidential boreholes
        - 613 less than 100 m - unrepresentative due to confidential boreholes
    - 3 km buffer – circa 100 boreholes in 36 km^2

D2-253 (Cont.)

- 6 greater than 50 m (unrepresentative – depth not assigned in database –confidential ICI boreholes at Warmingham Brinefield; depth likely to be >100 m)
- 5 greater than 100 m (unrepresentative – depth not assigned in database –confidential ICI boreholes at Warmingham Brinefield; depth likely to be >100 m)
- 93 less than 50 m - unrepresentative due to confidential boreholes
- 95 less than 100 m - unrepresentative due to confidential boreholes

- 1 km buffer – 19 boreholes in 1 km^2 – all confidential and thus depths not known

NW England

Preesall – Fig. 56

General geological sequence in areas of main potential:

- Mercia Mudstone Group (greater than 800 m thick)
  - glacial drift deposits – variable thicknesses between
  - Possible halite solution breccia (=Wilkesley Halite – variable thickness max of a few metres thick, if present)
  - Breckles Mudstone and Coat Walls Mudstone members (=Wych Byley Mudstone Fm) – 200-360 m thick in total.
    - Tight silty mudstones and claystones
    - Some halite as recrystallised 'clusters'
    - Infilled fractures – halite and gypsum (refer Fig. 10a)
  - Preesall Halite Member – 200 to approximately 500 m thick
    - Thinner to east over worked part of brinefield, being 100-130 m thick in east against Preesall Fault Zone
    - Intermittent marl (mudstone) and salt-bearing marl interbeds – in region of development. These are generally only thin mudstone and anhydrite interbeds are present, but
      - three more prominent zones of salt and non-salt interbeds 5 m, 6.19 m and 6.54 m thick were encountered
      - with the maximum individual non-salt bed thicknesses in these zones between 1.04 m and 1.76 m
    - Marl interbeds thicken slightly to east against the Preesall Fault, circa 1-1.5 km away
      - Thin partings up to 2.1 m thick, accounting for only 7 m thickness (12-13%) in a total thickness of 180 + m on western edge of brinefield.
      - 'anecdotal' evidence of individual bed being circa 17.5 m thick in old (poorly documented) mineshaft records
  - Thornton Mudstone Member – average 113 m thick
  - Singleton and Hambleton Mudstone formations (=Bollin Mudstone & Tarporley Siltstone Fm) – up to 311 m and 37 m thick respectively
    - Contains two halite beds
      - Mythop Halite – c. 0-50 m
      - Rossall Halite – c. 0-11 m
    - Tight silty claystone/mudstone
    - Some halite as recrystallised 'clusters'
- Sherwood Sandstone Group – thought to be greater than 500 m thick
- Faulting – 2 main graben bounding faults, some intragraben faulting, more to the south (Fig. 56a) than to the north (Fig. 56b)

D2-253 (Cont.)

- Borehole density – borehole data not fully representative — confidential ICI boreholes at Preesall Brinefield & depth not assigned in database (depth likely to be >100 m):
    - 11 km distance – c. 710 boreholes
        - 150 greater than 50 m
        - 142 greater than 100 m
        - 559 less than 50 m
        - 567 less than 100 m
    - 3 km buffer – circa 395 boreholes in 36 km^2
        - 142 greater than 50 m
        - 136 greater than 100 m
        - 253 less than 50 m
        - 259 less than 100 m
    - 1 km buffer – 155 boreholes in 16 km^2
        - 124 greater than 50 m
        - 123 greater than 100 m
        - 31 less than 50 m
        - 32 less than 100 m
- Oil/gasfields within 3 km – none
- Other salt cavern storage facilities within 3 km – none
- Other brine cavities – within 1 km
- Brine cavern collapse structures – between 0.5 and 2 km to the east

Typical cavern information:

- Proposal for up to 20 (24 originally) caverns in Preesall Halite (equivalent of Northwich Halite in the Cheshire Basin)
- Depths to top of caverns of between 220-425 m below ground level
- Probable maximum cavern height 55-290 m
- Up to 50 m of salt above top of caverns
- Salt thickness below cavern: 20% of max radius of cavern
- Likely maximum cavern diameter: 100 m
- Minimum salt pillar between caverns: 150 m (3 times cavern radius)
- Distance of cavern from significant fault: 150 m (3x cavern radius)
- Operating pressures of between
    - Minimum – 25 bar (2.5 MPa or 363 psi) i.e. above 30% of the vertical component of overburden pressure
    - Maximum - 75 bar (7.5 MPa or 1088 psi) i.e. below 83% of the vertical component of overburden pressure
- Subsidence estimates
    - Average rate of 0.2-0.3 mm per year, max being 0.5 mm (Ratigan)
    - Average rate of 0.4-0.8 mm per year, max being 1.4 mm (Kittitep)
- c. 460 m or more of Triassic Thornton Mudstone Member (113 m), Singleton (181-311 m) and Hambleton Mudstone (37 m) formations below the Preesall Halite
- Contains intermittent interbedded marls that to east may become thicker
- Marl beds in salt not soluble
- Wet rockhead conditions exist circa 1 km to east of site
- Two main basin bounding faults juxtaposing
    - impermeable strata over most of their lengths – may have salt associated with fault planes?
    - To the east, the Preesall Fault Zone juxtaposes Sherwood Sandstone Group against Mercia Mudstone Group, some 2 kms from potential storage site.
    - downthrow on Preesall Fault Zone is estimated to be greater than 500 m
    - Intervening ground has

D2-253 (Cont.)

        - Old wells
        - Brine caverns - numerous
        - Wet rockhead conditions (in east) – subsidence hollows
    - To west, Burn Naze Fault within 500 m. Throw is circa 400 m in south
- Possible cavern spacing – 230 m between well head and well head
- Oil/gasfields within 3 km – none
- Nearest major town/city – Fleetwood (2 km to W) & Blackpool (c. 7 km to SW), Preesall c. 2 km to E

Wessex Basin, southern England

Portland scenario - Fig. 57:

- Jurassic strata c. 820 m thick
    - Upper Jurassic – thin/absent
    - Middle Jurassic – 260 m plus
        - Forest Marble – 35-40 m thick near top
        - Frome Clay and Fullers Earth – c. 210 m thick
        - Inferior Oolite – 5-10 m thick at base
    - Lower Jurassic (Liassic) – c. 555-560 m thick
        - Bridport Sands (potential reservoir horizon) at top – 90-95 m thick
        - Thornecombe Sands and Junction Bed – c. 55 m thick (367-441 m)
        - Remainder mainly shales and clays
- Penarth Group – 50-55 m thick (818-869 m)
    - Limestone at top – c. 25 m thick
- Mercia Mudstone Group – total thickness of c. 1275 m
    - Upper mudstone unit c. 430 m
    - Saliferous beds
        - Top c. 2000 m
        - Main halite ("S7")
            - Top – c. 2360 m below ground level
            - c. 135-140 m thick
        - Mudstone interbeds increase towards base of saliferous beds
- Sherwood Sandstone – c. 300 m
- General gentle southerly dip to the succession from the Weymouth Anticline, axis being 1-2 km north of proposed Portland site
- Faulting – present in 'basement rocks' beneath the salt beds and Mesozoic 'cover rocks'. Have probably evolved separately and only the main controlling Abbottsbury-Ridgeway Fault system shows any connection following faulting and tectonic thinning of the salt beds (salt weld – refer Stewart et al., 1996, Harvey & Stewart, 1998; Chadwick & Evans, 2005)
- Series of relatively small faults mapped at surface in core of the Weymouth Anticline, major Abbotsbury-Ridgeway Fault mapped between 5 and 11 km to the north of the proposed storage area
- Borehole density
        - 11 km distance – c. 1200 boreholes
            - 83 greater than 50 m
            - 28 greater than 100 m
            - 1115 less than 50 m
            - 1171 less than 100 m
        - 3 km buffer – circa 583 boreholes in c. 81 km^2
            - 22 greater than 50 m
            - 0 greater than 100 m

D2-253 (Cont.)

        - 561 less than 50 m
        - 583 less than 100 m
    - 1 km buffer – 537 boreholes in c. 64 km^2
        - 20 greater than 50 m
        - 0 greater than 100 m
        - 517 less than 50 m
        - 537 less than 100 m
- Cavern/operational details
    - Top of target cavern salt interval c. 2100-2365 m
    - Top of caverns – c. 2400 m
    - Cavern salt interval c. 135 m
    - Salt roof – c. 35 m
    - Cavern height – 100 m, comprising
        - 80 m 'useable' height
        - 20 m sump
    - Cavern bases – c. 2500 m
    - Cavern widths – 90 m
    - Number of caverns – 14-18
    - Cavern spacing not known
    - Area of salt identified – c. 20 km^2
    - Operating pressures of between 130 and 350 bar (13/35 MPa or 1886/5076 psi)
    - Proposal is to operate in brine compensated mode (Egdon, 2007a)
    - Storage volume of each cavern – c. 70.8 Mcm (2.5 bcf)
    - One brine injection/withdrawal well
    - One gas injection/withdrawal well
    - Oil/gasfields within 3 km – none
    - Other Salt cavern storage facilities within 3 km – none
- Oil/gasfields within 3 km – none
- Nearest major town/city – Weymouth < 2 km to N & NW

NE England

Hornsea and Aldbrough scenarios (Fig. 58)

Permian salts

- Operating pressures between 120 and 270 bar (Buetal, 2002)
- Depth to top salt for caverns E England
    - Atwick/Hornsea – 1730-1830 m
    - Aldbrough - 1800-1900 m
    - Saltholme - circa 340-420 m
    - Wilton – circa 650-680 m

General geological succession at Atwick/Hornsea:

- Drift – c. 20-30 m
- Chalk – c. 500 m
- Lower Liassic clays & thin limestones – 40-45 m
- Rhaetic (hard shales) – 20-25 m
- Mercia Mudstone Group – 285-295 m
    - Micaceous sandstone at base – 12 m

D2-253 (Cont.)

- Sherwood Sandstone Group – 545-550 m
  - Lower Bunter shale at base – c.75 m
- Zechstein (total thickness of 530 m)
  - Anhydrites, salts and mudstones – c.100 m
  - Brotherton Formation (Upper Magnesian Limestone) – 70-75 m
  - Fordon Evaporites (storage interval) – 1665-1900 m (range). Lithologically variable with westerly thinning and loss of halite not reaching rockhead (Gaunt et al., 1992; Gaunt, 1994; Berridge & Pattison, 1994)
    - More easterly succession – thick basinward facies, deposited on basinal slope of underlying EZ2 carbonates (Kirkham Abbey Formation). Contains mainly halite with anhydrite dominating the thin upper and lower parts
    - Westerly, thinner transgressive facies from the Kingston upon Hull region westwards, halite disappearing by the Goole, Doncaster Isle of Axholme area
      - lowermost 8 m in the Risby borehole being massive anhydrite, containing layers of anhydritic dolomite and thin red silty mudstone
      - rest of sequence 41 m thick, comprising halite with layers up to 3 m thick of anhydrite, dolomitic mudstone and some thin bituminous dolomitic limestone
      - Grimsby-Patrington area, Fordon evaporites are 20-80 m thick, dominantly halite with some associated interbedded anhydrite. Thinning to 10-25 m thick in southwest of region, and passing laterally into thin red mudstones and siltstones with minor anhydrite. But few details available.
      - To north into the North Allerton district, the Fordon Evaporites again thin and show lithological change laterally towards the Permian crop line, with loss of the halite units (Smith, 1994; Frost, 1998)
  - Lower Magnesian Limestone – 85-90 m
- Rotliegend (sandstone) – 25-30 m
- Carboniferous (firm-hard coarse sst) - >8.5 m
- Faulting – none mapped at surface
- Boreholes
  - 11 km distance – c. 295 boreholes
    - 35 greater than 50 m
    - 9 greater than 100 m
    - 258 less than 50 m
    - 286 less than 100 m
  - 3 km buffer – circa 93 boreholes in 35 km^2
    - 17 greater than 50 m
    - 4 greater than 100 m
    - 76 less than 50 m
    - 89 less than 100 m
  - 1 km buffer – circa 48 boreholes in 16 km^2
    - 8 greater than 50 m
    - 4 greater than 100 m
    - 40 less than 50 m
    - 44 less than 100 m
- Top of target cavern salt interval c. 1720-1820 m
- Cavern salt interval c. 135 m
- Maximum cavity diameter/height – c. 90 m and 90 m

D2-253 (Cont.)

- Salt above cavity/below cavity – 40 m (including 10 m anhydrite)/40 m
- Number of caverns – 14-18
- Spacing between wellheads - > 400 m
- Operating pressures of between 120 and 270 bar (12/27 MPa or 1741/3916 psi)
- Oil/gasfields within 3 km – none
- Nearest major town/city – Hornsea c. 2.5 km to S, Hull c. 17 km to SW (updip)

General geological succession at Aldbrough same as Atwick

- Boreholes slightly different:
    - 11 km distance – c. 633 boreholes
        - 34 greater than 50 m
        - 6 greater than 100 m
        - 603 less than 50 m
        - 631 less than 100 m
    - 3 km buffer – circa 30 boreholes in 21 km^2
        - 0 greater than 50 m
        - 0 greater than 100 m
        - 30 less than 50 m
        - 30 less than 100 m
    - 1 km buffer – circa 1-5 boreholes in 9 km^2
        - 0 greater than 50 m
        - 0 greater than 100 m
        - 1-5 less than 50 m
        - 0 less than 100 m
- Nearest major town/city – Hornsea c. 8 km to N, Hull c. 11.5 km to SW (updip)

D2-253 (Cont.)

Wilton and Saltholme scenarios

General geological succession Wilton (Kirkleatham Bh):

- Lower Jurassic at crop – c. 125-150 m
- Triassic – c. 475 m thick
    - Penarth Group – c. 15-20 m thick
    - Mercia Mudstone Group – c. 250-255 m thick
    - Sherwood Sandstone Group – c. 205-210 m thick
- Permian – c. 355 m thick
    - Upper marls, anhydrites - c. 67 m thick
    - Main (Boulby) halite (host salt for caverns on Teesside, NE England) – c. 50 m thick
    - Permian Magnesian Limestone – c. 230 m thick
- Carboniferous – > 177 m
- Faulting – some faults mapped at surface within 3-4 km of Wilton facilities
- Operating pressures: not known
- Boreholes
    - 11 km distance – circa 6500 within 11 km of general area likely
        - 209 greater than 50 m
        - 119 greater than 100 m
        - 6303 less than 50 m
        - 6393 less than 100 m
    - 3 km buffer – circa 1530 boreholes in 3 km of general area likely
        - 33 greater than 50 m
        - 15 greater than 100 m
        - 1497 less than 50 m

        - 1515 less than 100 m
    - 1 km buffer – circa 3294 boreholes in 1 km of the general area likely
        - 121 greater than 50 m
        - 83 greater than 100 m
        - 3173 less than 50 m
        - 3211 less than 100 m
- Nearest major town/city – Teesside (Middlesbrough) developed above and around the Saltholme site, and c. 2 km to W of Wilton site

General geological succession Saltholme (Kirkleatham Bh) - refer Wilton area

- Sherwood Sandstone Group and thin Mercia Mudstone Group at crop
- Faulting –
    - some faults mapped at surface within 4.5-8.5 km N of likely Saltholme area
    - some faults mapped at surface within 4.5 km W of likely Saltholme area
    - some faults mapped at surface within 7-8.5 km S of likely Saltholme area
- Boreholes
    - 11 km distance – circa 7650 within 11 km of general area likely
        - 231 greater than 50 m
        - 132 greater than 100 m
        - 7417 less than 50 m
        - 7516 less than 100 m
    - 3 km buffer – circa 4287 boreholes in 3 km of general area likely
        - 146 greater than 50 m
        - 99 greater than 100 m
        - 4141 less than 50 m
        - 4188 less than 100 m
    - 1 km buffer – circa 2142 boreholes in 1 km of the general area likely
        - 109 greater than 50 m
        - 75 greater than 100 m
        - 2033 less than 50 m
        - 2067 less than 100 m

D2-253 (Cont.)

Appendix 8 Brief description of the presence of H_2S in oilfields, the process of drilling an exploration well/injection well and unlined rock caverns

This Appendix provides a brief summary of the presence and dangers of H_2S, the process of drilling a standard hydrocarbon exploration and production (or injection) well and the casing programs often undertaken. For more detailed information visit http://www.oilandgas.org.uk/issues/storyofoil/exploration-02.htm and http://www.glossary.oilfield.slb.com/. There is also more detail relating to unlined rock caverns and storage of hydrocarbons.

Presence of H_2S in oilfields

Oil and natural gas are the products of the thermal conversion of decayed organic matter (called kerogen) trapped in sedimentary rocks. Methane (CH_4) is the main component of natural gas, comprising 70 to 90%, while other gaseous hydrocarbons, butane, propane, and ethane, account for up to 20%. Naturally occurring contaminants present in natural gas and which have to be removed at natural gas processing facilities, include water vapour, sand, oxygen, carbon dioxide, nitrogen, hydrogen sulphide (H_2S) and rare gases such as helium and neon. High-sulphur kerogens release H_2S during decomposition, which stays trapped within the oil and gas deposits and is frequently encountered in oilfields, often to high levels, as in west Texas (Schlumberger, 2007).

During oil exploration and production, H_2S may enter drilling muds from subsurface formations and is also generated by sulphate-reducing bacteria in stored muds. Other sources of natural H_2S emissions are volcanoes and geothermal sources such as hot springs. Natural gas, or any other gas mixture which contains significant amounts of H_2S, is generally termed 'sour' if there are more than 5.7 milligrams of H_2S per cubic meter of natural gas. This is equivalent to approximately 4 ppm by volume (http://www.naturalgas.org/naturalgas/processing_ng.asp). Although the terms 'acid gas' and 'sour gas' are often used interchangeably, a sour gas is any gas that contains H_2S in significant amounts, whereas an acid gas is any gas that contains significant amounts of acidic gases such as CO_2 or SO_2. CO_2 by itself, therefore, is an acid gas but it is not a sour gas.

The H_2S is removed ('scrubbed') from the sour gas by a process commonly referred to as 'sweetening' at what are termed desulphurization plants. Removal of H_2S is normally done by absorption in an amine solution, while other methods include carbonate processes, solid bed absorbents (including solid desiccants like iron sponges) and physical absorption. The 'amine process' (also called the Girdler process) is used in 95% of US gas sweetening operations (http://www.naturalgas.org/naturalgas/processing_ng.asp). In this process, sour gas is passed through a tower containing the amine solution, which has an affinity for sulphur and which absorbs it. Two main amine solutions are used: monoethanolamine (MEA) and diethanolamine (DEA). The emerging gas is virtually free of sulphur compounds and the H_2S can be removed from the amine solution, allowing it to be reused to treat more sour gas.

The presence of H_2S in an oilfield and, if exposed to the gas during oil and gas production, its possible impacts on human health, is a potential concern for potential UGS operators. H_2S is a toxic, colourless gas that is odourless at high concentrations but has a smell of rotten eggs in low concentrations. Because H_2S is heavier than air, it tends to accumulate in low-lying areas. It is an extremely poisonous gas and a few seconds of exposure in concentrations of anywhere between 750 and 10,000 ppm can prove lethal to people and animals. However, the effect of H_2S depends

D2-253 (Cont.)

on duration, frequency and intensity of exposure and the susceptibility of the individual (Schlumberger, 2007: http://www.glossary.oilfield.slb.com/Display.cfm?Term=hydrogen%20sulfide). Research conducted at the University of Southern California Medical Facility has established nervous system damage can occur even at concentrations in air as low as 1 ppm (Chilingar & Endres, 2005).

H_2S is hazardous to rig workers and is also corrosive, causing sulphide stress-corrosion cracking of metals, which may require costly special production equipment such as stainless steel tubing. A recent study concluded that H_2S "will eventually destroy the integrity of both the steel and cement relied upon to prevent gas migration, including abandonments performed to the current standards of the DOGGR [Division of Oil, Gas and Geothermal Resources]. The corrosive conditions of hydrogen sulphide are well known, and have defied engineering solutions." (Chilingar & Endres, 2005). Whilst this may be an extreme conclusion, it highlights the importance of proper procedures and monitoring of the presence and effects of H_2S on plant and infrastructure. H_2S is a recognised problem, with established procedures to mitigate it.

Effects of H_2S

H_2S variously acts as an irritant or an asphyxiant, depending of the concentration of the gas and the length of exposure. The primary route by which humans are affected is inhalation, although it also affects the eyes. Essentially, H_2S blocks cellular respiration, resulting in cellular anoxia, a state in which the cells do not receive oxygen and die. The human body detoxifies H_2S by oxidizing it into sulphate or thiosulphate by haemoglobin-bound oxygen in the blood or by liver enzymes (Knight & Presnell, 2005; Skrtic, 2006). Lethal toxicity occurs when H_2S is present in concentrations high enough to overwhelm the body's detoxification capacity.

Some scientific references have reported exposure to concentrations of H_2S as low as one part per million can affect the central nervous system, resulting in neuropsychological effects (e.g. Chilingar & Endres, 2005), however, there is not scientific consensus on this point (UNEP[6]: http://www.uneptie.org/pc/apell/disasters/china_well/china.htm#impacts). At levels up to 100 to 150 ppm, H_2S is a tissue irritant, causing Keratoconjunctivitis (combined inflammation of the cornea and conjunctiva), respiratory irritation with lachrymation (tears) and coughing. Skin irritation is also a common symptom. Instantaneous loss of consciousness, rapid apnea (slowed or temporarily arrested breathing) and death may result from acute exposure to levels above 1,000 ppm (Knight & Presnell, 2005; Skrtic, 2006).

The non-lethal effects can be summarized as:

- *neurological* –symptoms including dizziness, vertigo, agitation, confusion, headache, tremors, nausea, vomiting, convulsions, dilated pupils, and unconsciousness,
- *pulmonary* – symptoms including cough, chest tightness, dyspnea (shortness of breath), cyanosis (turning blue from lack of oxygen), haemoptysis (spitting or coughing up blood), pulmonary oedema (fluid in the lungs), and apnea with secondary cardiac effects (Snyder et al., 1995).

Incident at Gasfield, Chongquing, China

An incident in China illustrates the potentially deadly effects of H_2S release during production from a gasfield. The disaster took place at the Chuandongbei gas field in Gao Qiao town in the north eastern part of Chongqing province. The incident involved a gas well blowout, which occurred at 10:00 pm on Tuesday, 23 December 2003 and resulted in the release of natural gas and H_2S. According to press reports, the accident occurred as a drilling team was working on the 400 meter deep well and sent toxic fumes (sour gas - a high concentration of natural gas and H_2S) shooting 30 metres out of a failed well (UNEP: http://www.uneptie.org/pc/apell/disasters/

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[6] UNEP: United Nations Environment Programme

china_well/china.htm#impacts).

The *China Daily* newspaper described the tragedy as "the worst of its kind in China's history". "The poisonous gas hovering in the air made an area of 25 square kilometres a death zone, as many villagers were intoxicated by the fumes in their sleep". Worst hit was the village of Xiaoyang next to the gas well, where 90% of the residents were killed, "many having died in their sleep or were too old to escape" (WSWS, 2003).

The incident was reported in Lloyd's Casualty Week for 23rd Jan 2003 as follows: "officers investigating a gas leak which killed 243 people in western China have arrested three oil company workers on suspicion of dismantling safety features and mishandling drilling equipment.....one of China's worst industrial accidents.....the investigation has forced the resignation of a vice president of state owned China National Petroleum Corporation. .....The accident sent a deadly cloud of poisonous hydrogen sulphide over nearby villages in a poor mountainous area. Villagers died in their sleep or were struck down while trying to flee. More than 9,000 people were treated for injuries and 60,000 were forced to evacuate the area. Hospitals reported..... 396 were still being treated for injuries, several of them in critical condition."

Many factors appear to have led to the release, most related to human error and poor operational and maintenance procedures, including operation under health and safety regulations that were far less stringent than those established in the UK. The differences in approach to the issues of health and safety in industrial activities is further is illustrated by China's extremely poor record of coalmine disasters, but the incident nevertheless highlights the importance of awareness of the problem and correct planning.

The question arises as to how the consequences of an incident could be reduced. A gas well blowout represents an uncontrolled flow of gas, oil, or other well fluids from a wellbore (borehole) into the atmosphere. A blowout usually results from a combination of factors, such as human error and equipment failure. If, for any reason, blowout prevention procedures built into all modern wells drilled during oil and gas exploration and production fail, UNEP suggest the best action to reduce the impact is to immediately ignite the well. The ignition converts the H_2S to sulphur dioxide, which disperses more effectively as the heat carries it upwards, resulting in lower concentrations at ground level. However, even if all prevention procedures are taken, there is no 'zero risk' in industrial operations and emergency planning for accidents should be in place, UNEP having suggested the following actions to reduce the impacts of potential accidents and blowouts:

- Keep people away from the source of the "accident". Normally the population should be at a "safe" distance such that if an accident takes place, the distance itself will mean that the public do not receive a lethal dose. In this specific accident the population was as close as 50 metres to the site, which increased the number of people affected
- Respond to people in a quick and efficient way - how the first response to the accident is handled will determine the potential consequences
- Be prepared for the accident, which does not appear to have been the case in the case of the Chuandongbei incident

Drilling of exploration wells, casing and tubing

A drilling platform provides storage for the drilling equipment, the base from which the drilling is done and generates onsite power for the drilling operations. A drilling derrick rises above the drill floor, housing hoisting equipment that raises or lowers a drillstring. The latter comprises 30-foot (c. 10 m) lengths of drill pipe screwed together. At the bottom of the drillstring, drill collars (heavy pipe-sections) maybe screwed on to provide added weight to a drill bit, which can vary in size and type. The drill bit is rotated either by turning the whole drillstring ("rotary drilling") or by using a downhole turbine that rotates as drilling fluid is pumped through it. As the well is

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drilled to the length of the drillstring, a new section of drill pipe is screwed onto the top of the drillstring and drilling recommences.

The action of the drill bit grinds up the rock into small chips of rock ("cuttings"). Drilling fluid (also called "mud"), which is mainly water-based, is pumped continuously down the drillstring while drilling. This acts as a lubricant and washes up the rock cuttings, which are brought to the surface by the circulating drilling fluid outside the drill pipe. The rock cuttings are used to determine the nature and the age of the rock types being drilled, and in exploration, the presence of hydrocarbons. Most importantly, however, the drilling fluids balance the pressure of fluids in the rock formations below to prevent blowouts caused by hitting pockets or layers of higher pressure. If the borehole is to go through halite (salt) beds then a drilling fluid that will not cause dissolution of the salt is used and is commonly a brine solution.

If laboratory tests are needed on potential reservoir or caprock, a solid core of rock can be drilled using a special hollow drilling bit of the same lengths as that of the normal drill pipe. Each length of core retrieved requires the entire drillstring to be pulled out of the well and then reinserted. Coring, therefore, represents an expensive operation, generally only undertaken when neccesary.

Important information on the type of rock drilled and the fluids it contains can be obtained either while actually drilling, or after drilling and before running casing. Electronic measuring devices (geophysical logging tools) are lowered into the well - either while drilling (as part of the drillstring) or after drilling on "wireline", permitting various types of measurement that give indications of rock type and porosity and the presence of oil or gas. Other devices measure wellbore (borehole) diameter, dip of strata and the direction of the hole. Cores of rock from the borehole (side)walls can also be taken from deep underground.

After the hole is drilled to a given depth, a steel pipe (casing) slightly smaller than the hole is placed down the hole and is secured with cement. The casing provides structural integrity to the newly drilled wellbore in addition to isolating potentially dangerous high pressure or chemically differing zones from each other and from the surface. In salt beds, casing can be inserted from above to below the top of the salt. This protects the upper salt beds as drilling continues into the underlying formations with fluids that might otherwise dissolve the salt.

Once the zones are safely isolated and the formation protected by the casing, the well can be drilled deeper with a smaller bit and also then cased with a smaller size casing. It is not uncommon for modern wells to have between two and five sets of progressively smaller hole sizes, each cemented with casing.

Well completions - casing and casing string

All wells, including those drilled for producing water or hydrocarbons, at least when first drilled have openhole sections, but may be completed in a number of ways. Rarely, where no freshwater zones exist or the borehole remains in a stable condition after drilling (i.e. suffers no collapse or breakouts), the geology allows openhole completion. More usually, something has to be placed down the borehole, either during or immediately after drilling, to isolate zones and stabilise the borehole, preventing collapse. This may range from as little as a packer on production tubing above an openhole completion, to casing with or without a system of mechanical filtering elements outside a perforated pipe section. There are also what are known as "intelligent" completions, comprising a fully automated measurement and control system that optimises reservoir management without requiring human intervention.

Casing in its simplest form is large-diameter steel pipe, generally in sections around 13 m (40 ft) length with a threaded connection at each end. It is available in a range of material grades and sizes, internal diameters of which typically range from 4" to 30". It is lowered into an open hole borehole (wellbore) and cemented in place in order to stabilize the wellbore. The operation during which the casing is put into the wellbore is commonly called "running pipe." The casing

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(Cont.)

forms a major structural component of the wellbore and as indicated, is run to serve several important functions:

- To prevent the formation wall from caving into the wellbore
- To protect fresh-water formations
- To isolate a zone of lost returns (drilling cuttings and fluids)
- To isolate formations with significantly different pressure gradients
- To prevent the flow or crossflow of formation fluids
- To provide a means of maintaining control of formation fluids and pressure as the well is drilled
- To provide a means of securing surface pressure control equipment and downhole production equipment, such as the drilling blowout preventer (BOP) or production packer

Casing is assembled as a series of casing joints to form a casing string of the required length and specification for the wellbore in which it is installed. Most casing joints are manufactured with male threads on each end and are joined together by short-length casing couplings with female threads, known as collars. Casing joints may also be fabricated with male threads on one end and female threads on the other.

Casing is usually manufactured from plain carbon steel that is heat-treated to varying strengths but may be specially fabricated of stainless steel, aluminium, titanium, fibreglass and other materials. As well as being designed to withstand a variety of forces such as collapse, burst, and tensile failure, it also is designed to withstand the deleterious effects of fluids such as chemically aggressive brines. Casing may also be protected by injection of corrosion inhibitors down the well.

The annular space between all casing strings is usually left fluid filled although many are cemented back to the surface, or back to a sufficient level to ensure a fluid seal between the casing and the borehole and pressure integrity throughout the system.

The bottom of the casing string comprises a short assembly, known as the casing shoe, which is typically manufactured from a heavy steel collar and profiled cement interior, screwed to the bottom of the casing string. The rounded profile helps guide the casing string past any ledges or obstructions that would prevent the string from being correctly located in the wellbore.

Most oilfield casing is of approximately the same chemistry (typically steel), and differs only in strength, which is determined by the heat treatment applied. A system for the identification and categorization of the strength of casing materials exists, which is important to consider when, for example, the presence of H_2S is anticipated. In general, the higher the yield strength, the more susceptible the casing is to sulphide stress cracking. Therefore, the well designer may not be able to use casing with strength as high as might be preferred (refer Schlumberger: http://www.glossary.oilfield.slb.com/Display.cfm?Term=casing%20grade).

Coiled tubing

Coiled tubing is a continuous, jointless, high-pressure-rated hollow steel cylinder. Production tubing traditionally was made up of jointed sections of pipe, similar to the string of pipe used for drilling, but coiled tubing is now more generally used in this application. It is transported to the wellsite on a reel holding up to 7,000 metres. Special equipment is used to insert the tubing through the wellhead into the wellbore. This method is considerably quicker and more efficient than joining sections of pipe.

Further detail on unlined rock caverns

Section 2.2.8.4.2 discussed the concepts of unlined rock caverns and the deployment of water curtains to provide product containment. The basics were discussed and this section provides further detail on the storage technology, particularly the depths of the caverns and the pressures

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required and developed. Examples are also described where fault zones and leakage pathways exist and have been sealed to provide tightness.

The maximum pressure in the cavern that does not lead to leakage is referred to as the critical gas pressure and is the pressure that defines the capacity of any particular storage facility. The critical gas pressure and gas storage capacity is dependent upon groundwater pressure and cavern depth. To maintain high water pressure in the surrounding rocks, the storage cavern is located either at a sufficient depth and relies upon containment either by the hydraulic gradient and pressure or by the additional installation of a 'water curtain' (Fig. 7; e.g. Liang & Lindblom, 1995; Yamamoto & Pruess, 2004).

To illustrate how the depth of the cavern plays an important role in increasing the groundwater pressure surrounding storage caverns and thus increasing critical gas pressure and gas storage capacity, Liang & Lindblom (1994) calculated pressures for a four cavern configuration under a 10 MPa (1450 psi) water curtain pressure scenario. As the depths of the cavern increases from 200 m to 800 m below groundwater level, then the critical gas pressure increases from 6.45 MPa (936 psi) to 9.97 MPa (1446 psi) and from 8.18 MPa (1186 psi) to 9.99 MPa (1449 psi), for roof curtain and roof and wall curtain scenarios, respectively.

In LRC's, the presence of highly heterogeneous 'conductive' media such as fractured rock and fault zones, could form local flow paths, permitting the escape of stored product (gas), with an unsaturated fault zone connected to the storage cavern having the potential to quickly lead to a gas blowout. However, their presence does not preclude safe storage and to eliminate such zones, treatments such as pre/post grouting or additional water-curtain boreholes would be essential. Even partially saturated zones may retard or prevent gas leakage hence the critical need to ensure that water saturation of the rock surrounding the cavern is maintained. Investigations and simulations suggest that even if the water curtain were suddenly impaired by an accident, the gas plume does not quickly migrate to the ground surface, but would take several months (Yamamoto & Pruess, 2004).

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Containment of product may, however, rely on the country rock being impermeable, although this is generally not the case. An example of a facility using this principle is one constructed in crystalline rock (granodiorite) of the Bohemain Massif at Háje, 113 km (70 miles) SW of Prague in the Czech Republic. In 1998, the facility became one of the first commercial natural gas cavern storage facilities constructed in crystalline rock (RWE, 2005). Five injection wells control the gas storage operations and the facility is formed by a series of unlined tunnels excavated at a depth of around 960 m with cross sectional areas of between 12 and 15 m^2 and a total length of 45 km, providing a gas capacity of 620,000 m^3. The tunnels were left unlined except for areas of high water infiltration through cracks in the rock massif, which were sealed by grouting. Permanent bracing was constructed only in places where there was a risk of tunnel collapse. Grouting was performed in the area of boreholes and concrete plugs in order to increase the rock impermeability. The system uses a water curtain to prevent gas migration out of the cavern into the the cracks and fissures in the host rock, with water collected in a basal sump area.

Following construction, natural gas was first pumped into the underground storage in January, 1998 to perform gas equipment and pressure seal tests, following which, the facility was commissioned on July 14, 1998. A local seismic network with seven stations was installed to monitor both local and regional seismic effects in the underground gas storage area. Over 300 seismic events were recorded during construction and activity continues (Málek et al., 2000; Málek & Brokesova, 2003). Epicentres are very shallow (0.3-1.9 km), are parallel to a major fault in the area and may be related to old mining activity and rising groundwater levels that aid release of seismic energy. The safety of the gas storage facility has not been affected, but plans to increase storage pressures may increase the risk of further seismic events. A grid of gas detectors has also been installed, monitoring ground methane levels.

On a similar note, research has been undertaken into the potential for development of a Refrigerated-Mined Rock Cavern Technology (RMRCT) for storage of natural gas in granitic

rock in the northeast U.S (CAES Development Co., 2004). The concept involves mining voids deep in unfractured crystalline rock and storing natural gas by chilling and compressing it to reduce the storage space required. Considerable technical risk is associated with a facility of this type, some of which relates to unknowns associated with large-scale cyclic internal pressurisation of a mined cavern in hard rock.

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(Cont.)

Glossary

Alluvium: sediment deposited by the action of rivers

Anastomosing: of streams, branching and rejoining irregularly to produce a net like pattern. Often used when describing fault zones and their internal structure of smaller faults

Anhydrite: mineral, $CaSO_4$, forms rock

Antithetic: a lesser fault with opposite dip and downthrow to a related major fault

API: The American Petroleum Institute gravity, or ***API gravity***, is a measure of how heavy or light a petroleum liquid is compared to water. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids. Although mathematically API gravity has no units, it is nevertheless referred to as being in "degrees". API gravity is graduated in degrees on a hydrometer and was designed so that most values would fall between 10 and 70 API gravity degrees.

Apical: belonging to an apex; situated at the tip; hence ~ly

Archaea: the archaea or archaebacteria are a major group of single-celled microorganisms. Like bacteria, archaea lack nuclei. Archaea were originally found in extreme environments but have since been found in all habitats.

Archaean: refers to a period of Proterozoic (PreCambrian) time (> 545 Ma before present)

Aquiclude: an impermeable bed within an aquifer

Aquifer: a water-bearing layer/rock (geological formation) containing sufficient saturated material to be considered economical in the supply of water.

Arenaceous rocks: a group of detrital sedimentary rocks, typically sandstones

Argillaceous rocks: a group of detrital sedimentary rocks, commonly clays, shales, mudstones, siltstones and marls

Bituminous: impregnated with bitumen, a naturally occurring hydrocarbon mineral ranging in consistency from a thick liquid to a solid (asphalt). Subitiminous is of lower bitumen content

Borehole: a hole drilled down into the rock from which samples or cores can be taken, or measurements of the rocks can be made

Boudinage: (French *boudin*, 'sausage') refers to a structure arising from tensional forces, usually involving stretching of a competent bed parallel to the bedding plane

Breccia: a coarse to very coarse grained sedimentary rock, or referring to rock fragments, caused by either faulting or collapse of intact beds (above say dissolving salt beds within the circulating groundwater zone)

Brinefield: an area of (concealed/underground) salt mined by solution processes

Cataclasis: the process of mechanical fracture or break-up of rocks, usually associated with faulting

Clastics (clastic rocks): rocks built up of fragments of pre-existing rocks which have been produced by the process of weathering and erosion and in general transported to a point of deposition. Typically arenaceous rocks, conglomerates, breccias etc.

Competent: referring to a rock layer which, during folding, flexes without appreciable flow or internal shear and ultimately likely to fracture

Condensate: A low-density, high-API gravity liquid hydrocarbon phase that generally occurs in association with natural gas. Its presence as a liquid phase depends on temperature and pressure conditions in the reservoir.

Conformable: describes a continuous series of geological strata, without any break in sediment deposition.

Cretaceous: the geological period immediately after the Jurassic

Crust: the uppermost part of the lithosphere. In the UK context we refer only to 'continental' crust, which comprises relatively low density rocks of acid-intermediate composition, typically 30 km thick, overlying denser mantle rocks of ultramafic (ultrabasic) composition. The base of the crust (the crust/mantle boundary) is termed the Mohorovicic discontinuity (Moho)

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Dessication: referring to drying out, usually referring to dessication cracks that develop in mudstones or evaporitic sequences. These rocks were originally deposited under water and the cracks are produced by the evaporation of the water and rapid drying up of the surface of the deposit

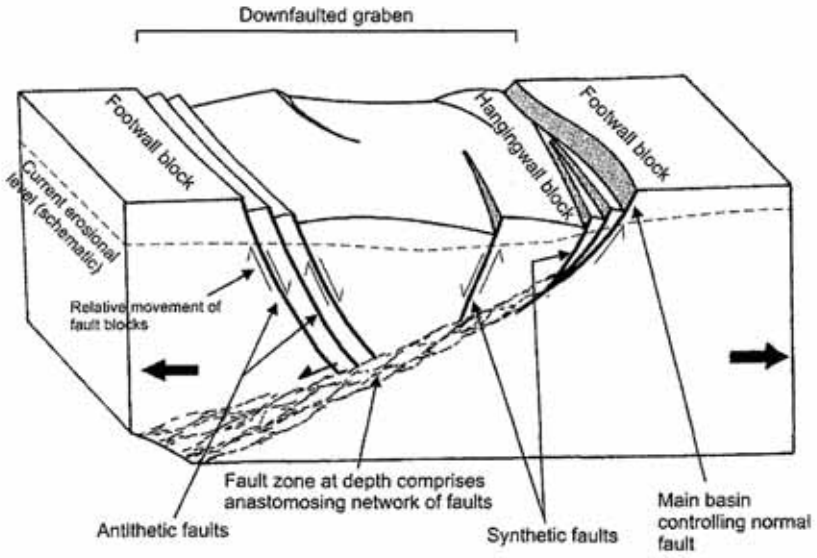
Downthrow: the downward movement of a fault block (or beds) along a fault surface

Drift: unconsolidated superficial deposit

Erosion: the weathering and removal of rock at surface

Evaporite: a sediment resulting from the evaporation of enclosed or partly enclosed saline water. Most evaporites are derived from bodies of sea water. Typically evaporitic sequences show are rhythmically bedded and full sequences may contain mixtures of potash and magnesium salts, rock salt (halite), gypsum or anhydrite and calcite and dolomite.

Fault: a planar discontinuity representing a fracture or shear-surface between blocks of rock (containing beds or layers) within the earth, across which rocks show relative displacement. Refer cartoon sketch below for other main fault terminology included in the glossary. Faults can exist on a range of scales with lengths from a few centimetres to tens of hundreds of kilometres. From a seismotectonic viewpoint, we are interested in larger faults, many kilometres in length and penetrating to mid or lower crustal depths (several kilometres), which may have fault surface areas of many hundreds of km^2. Faults are categorised according to the nature of displacement across them. Thus normal faults are characterised by displacement of the hangingwall-block, down the fault surface and are commonly produced during crustal extension. Strike-slip (transcurrent) faults are characterised by components of horizontal displacement of the hangingwall-block, along the fault surface. Reverse faults are characterised by displacement of the hangingwall-block, up the fault surface and are commonly produced during crustal compression.



Fault zone: tabular region containing many parallel or anastomosing faults.

Fm: stratigraphic nomenclature, abbreviation for formation. A **geologic formation** is a formally named rock stratum or geological unit. Formations are lithostratigraphic units which are defined by primary lithology.

Gas hydrates: gas hydrates, also called clathrates, are crystalline solids which look like ice, and which occur when water molecules form a cage-like structure around smaller 'guest molecules'. Water crystallizes in the cubic system in clathrates, rather than in the hexagonal structure of normal ice. The most common guest molecules are methane, ethane, propane, isobutane, normal butane, nitrogen, carbon dioxide and hydrogen sulfide, of which methane occurs most abundantly in natural hydrates.

Graben: structural term for a downthrown block between normal faults.

Halite: salt mineral, NaCl, rock forming

Halokinetic: referring to the process whereby salt beds are disturbed and structures formed by the movement of salt under gravitational forces (halokinesis), including salt swells, pillows, diapirs, domes, stocks and walls

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Hangingwall/ Footwall block: forming the downthrown (hangingwall) and upthrown (footwall) sides of faults

"Haselgebirge" (facies): halite crystals set in mudstone, forming a rock intermediate between halite and mudstone.

Horst Block: an upfaulted area between two parallel, but opposite downthrowing faults

Hydrostatic pressure: the 'normal' or hydrostatic pressure to be expected in pore water at any depth is the pressure in a column of water extending from this depth to the surface. Thus the hydrostatic pore pressure will be about 0.4 times the lithostatic or rock pressure if a mean density for the rock column is 2.5 g/cc. Pore pressures greater than hydrostatic can be generated in a variety of ways, including compaction of sediments by rapid burial or tectonic processes and dehydration of mineral assemblages during metamorphism.

Intensity: measurement of strength of shaking produced by an earthquake at a certain location. Intensity is determined from effects on people, human structures and the natural environment

Intracrystalline slip: related to ductile deformation of rocks and is the movement of crystal lattice defects (dislocations) through a crystal to produce shape changes in the crystal and ultimately solid rock. Requires high temperatures and geological time frames. Dislocations may glide along or climb through a crystal lattice.

Jurassic: the geological period immediately after the Triassic

Lithosphere: the outermost shell of the Earth comprising the crust and the uppermost mantle. Made up of internally rigid, but mobile blocks known as 'plates' (as in 'plate tectonics'). Typically 125 km thick beneath the UK, the base of the lithosphere is a thermomechanical boundary, corresponding to the onset of partial melting and a corresponding rapid decrease in viscosity.

Lithostatic (rock) pressure: the hydrostatic pressure generated at a depth below the ground surface due solely to the weight of overlying rocks of mean density in that interval.

LNG: abbreviation for Liquefied Natural Gas; is natural gas that has been processed to remove impurities or valuable components that could cause difficulty downstream and then condensed into a liquid at almost atmospheric pressure by cooling to approximately -163 degrees Celsius. LNG is transported by specially designed cryogenic ships and cryogenic road tankers; and stored in specially designed tanks.

Lower crust: lowermost part of the crust typically between ≈18 km and ≈30 km depth. Mechanically rather weak and probably characterised by ductile (aseismic) deformation in the current stress regime

LPG: abbreviation for Liquid Petroleum Gas; a mixture of hydrocarbon gases, which is a gas at atmospheric pressure and normal ambient temperatures, but can be liquefied when moderate pressure is applied, or when the temperature is sufficiently reduced

Lst: common abbreviation for limestone, a sedimentary rock

Ma: abbreviation for millions of years ago

Magnitude: energy scale used for earthquakes, measuring the energy released at the source of the earthquake. Determined from measurements on seismographs. A number of measurement scales are available, including the Richter Scale

Marl: claystone, slightly calcareous and/or silty

Mercia Mudstone Group: common abbreviation for Mercia Mudstone Group, part of the Triassic succession

Mudstone: claystone

Mylonite (zones): narrow planar zones of high strain in which deformation is intense relative to the adjacent (parent) rock and a fine-grained fault rock has been produced either by cataclasis, recrystallisation or both. Original usage was for rocks in which deformation was solely of a cataclastic nature, with no accompanying recrystallisation. Now more widely recognised that the grain size reduction in the fault rock has been by dynamic recrystallisation proceseses, with the rocks sometimes referred to as blastomylonites

Natural gas: a mixture of hydrocarbon and small quantities of non-hydrocarbons, primarily methane, that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature

NGL: abbreviation for Natural Gas Liquids, hydrocarbons that exist in a reservoir as constituents of natural gas but which are recovered as liquids in separators, field facilities or gas-processing plants

Outcrop: the area where a particular geological strata occurs at the surface.

Packer: A device that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the wellbore. Packers employ flexible, elastomeric elements that expand. The two most common forms are the production or test packer and the inflatable packer. The expansion of the former may be accomplished by squeezing the elastomeric elements (roughly doughnut shaped) between two plates, forcing the sides to bulge

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outward. In the latter, expansion is accomplished by pumping a fluid into a bladder (in much the same fashion as a balloon), but having more robust construction. Production or test packers may be set in cased holes and inflatable packers are used in open or cased holes. They may be run on wireline, pipe or coiled tubing. Some packers are designed to be removable, while others are permanent. Permanent packers are constructed of materials that are easy to drill or mill out.

Permeability: the intrinsic capacity of a geological material to transmit fluids. Linked to porosity.

Permian: the geological period immediately before the Triassic

Phyllosilicate: referring to a group of layer-lattice minerals, most commonly micas making up shales (micaceous)

Porosity: the percentage of the total volume of rock or soil that consists of pore space. Linked to permeability.

Post-sedimentary: having taken place after the sedimentation of a bed

Post-Triassic: having taken place after the Triassic period

Prospectivity: the term used to describe a geographical region, a country, a geological basin, a particular area or structure within a basin as attractive for hydrocarbon exploration by reason of its [technical] attributes (having the likely petroleum requirements of source, reservoir, cap rock and favourable trapping structures). It may also ultimately include legal and fiscal aspects that would contribute towards determining if an area were prospective.

psi, psia & psig: units of pressure describing the pressure resulting from one pound force applied to an area of one square inch (= lbf/sq in). **psi** is the abbreviation for pounds per square inch (or more accurately, pound-force per square inch), describing a pressure measured with respect to atmospheric pressure (the gauge reading is adjusted to zero at the surrounding atmospheric pressure). **psia** is the abbreviation for pounds(force) per square inch absolute, describing an absolute pressure per square inch that starts from a perfect vacuum (space) – it is gauge pressure plus barometric or atmospheric pressure (thus psia is affected by weather conditions). A good frame of reference is at sea level there is 14.7 psia. **psig** is the abbreviation for pounds(force) per square inch gauge, describing a unit of pressure relative to atmospheric pressure at sea level. Thus if a pressure gauge is calibrated to read zero in space, then at sea level on Earth it would read 14.7 psi. Thus a reading of 30 psig on a tyre gauge, represents an absolute pressure of 44.7 psi. **psi** is often used incorrectly instead of psig.

Quaternary: youngest age of earth's history, including the period of the ice age to now

Rheology: the study of the deformation and flow of matter under an applied stress

Rockhead: top of a geological formation at base of drift deposits

Seismic reflection data: data imaging the subsurface, acquired by recording sound waves reflected from rock layers in the subsurface. Measured and generally displayed in time

Sedimentary cover: young, relatively soft, relatively undeformed layered rocks, resting upon the crystalline upper crust. Often preserved within sedimentary basins, which can be several kilometres thick

Sedimentation: the act of depositing sediment to form beds and eventually rock

Shear-zone: a general term for a (roughly planar) surface or zone within the earth characterised by lateral (shear) displacements on either side. Similar to a fault, but generally showing ductile deformation of material along the shear-surface, whereas faults show brittle forms of deformation along the fault surface. Many faults are believed to pass downwards into shear-zones; deep in the crust the two terms become synonymous.

Siliciclastic: Silica-based sediments that are derived from weathered (broken down) pre-existing rocks, transported elsewhere and redeposited to form another rock (clastics). Examples of common siliciclastic sedimentary rocks include quartzitic conglomerate, sandstone, siltstone and shale. Other non-silica based rocks (including carbonates) can also be broken down and reworked to form other types of clastic sedimentary rocks.

Sole or soling out: the flattening or decrease in angle of a fault towards horizontal with depth. Often in the context of faults flattening out into salts, shale or evaporite deposits as the deformaton is taken up in a ductile manner.

Solid rock: the rocks below the drift (Quaternary) deposits

Sherwood Sandstone Group: common abbreviation for Sherwood Sandstone Group, part of the Triassic succession

Sst: common abbreviation for sandstone, a sedimentary (clastic) rock

Strain/strain rate: Strain is the ratio of a change of length to an initial length and thus has no dimension. A strain is generally expressed as a percentage change or as a fractional change. Thus if a line initially 10 cm long is shortened to 8 cm long, the change in length is 2 cm and the strain (shortening) is 0.2 (no units) or 20 percent (no units). The dimensions of strain rate are $[T^{-1}]$ and thus strain rate might be expressed as $10^{-9}sec^{-1}$. If the example of shortening by 20% takes place in one year (3.1536×10^7 sec), then the strain rate is $0.2/(3.1536 \times 10^7) = 6.3 \times 10^{-9}sec^{-1}$ (Hobbs et al., 1976).

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Subcrop: a subsurface ***outcrop***, such as where a geological strata intersects a subsurface plane.

Surfactant: a substance, e.g. a detergent, which has the effect of altering the interfacial tension of water and other liquids or solids

Syncline: rocks bent in a down fold, the opposite of an anticline

Synsedimentary: an action that took place during sedimentation, e.g. faulting of an area during sedimentation

Tectonic: subsurface movements caused by forces in the earth's interior

Tectonic thinning: having been thinned by a tectonic structure, generally a fault

Terrane: a term used to characterise a crustal or lithospheric block which has experienced a distinct geological (i.e. stratigraphic, faunal, structural, metamorphic, igneous etc) history with respect to adjacent terranes, with which it is in present tectonic contact. The tectonic contacts are fault-zones or shear-zones which may have very large displacements. The term was originally used in the American literature to characterise very far-travelled, exotic or 'suspect' terranes within the circum-Pacific cordilleras

Thrust-fault: low-angle fault (commonly dipping between 20° - 35°), characterised by reverse displacements in the geological past. Can penetrate to lower crustal depths when they constitute fundamental lines of crustal weakness.

Transcurrent fault: steeply-dipping to vertical fault-structure characterised by strike-slip displacements in the geological past

Triassic: a geological period, including the time of sedimentation of the Mercia Mudstone Group, containing major salt beds such as the Preesall and Northwich halites of NW England and the CheshireBasin respectively

Upper crust: the strong 'brittle' part of the crust typically at depths less than ≈18 km. As defined here, does not include the sedimentary cover

Vadose: the **vadose zone**, also termed the **unsaturated zone**, is the portion of Earth between the land surface and the zone of saturation, or top of the water table ("vadose" is Latin for "shallow")

Vuggy: relating to pore space that is within rock and that is significantly larger than grains, crystals or pore spaces beteen grains. Generally produced by dissolution amd is thus most often referred to in carbonate rocks (limestone chalk etc)

Wet/dry rockhead: wet rockhead is an area where the halite beds rise towards the surface and are progressively solved by groundwater. Thus there is a belt where only part of the halite sequence is preserved and across which halite is overlain by collapse breccias of the overlying mudstones. Dry rockhead is the area of halite beneath the rface, which is not affected by groundwaters where a complete sequence is preserved

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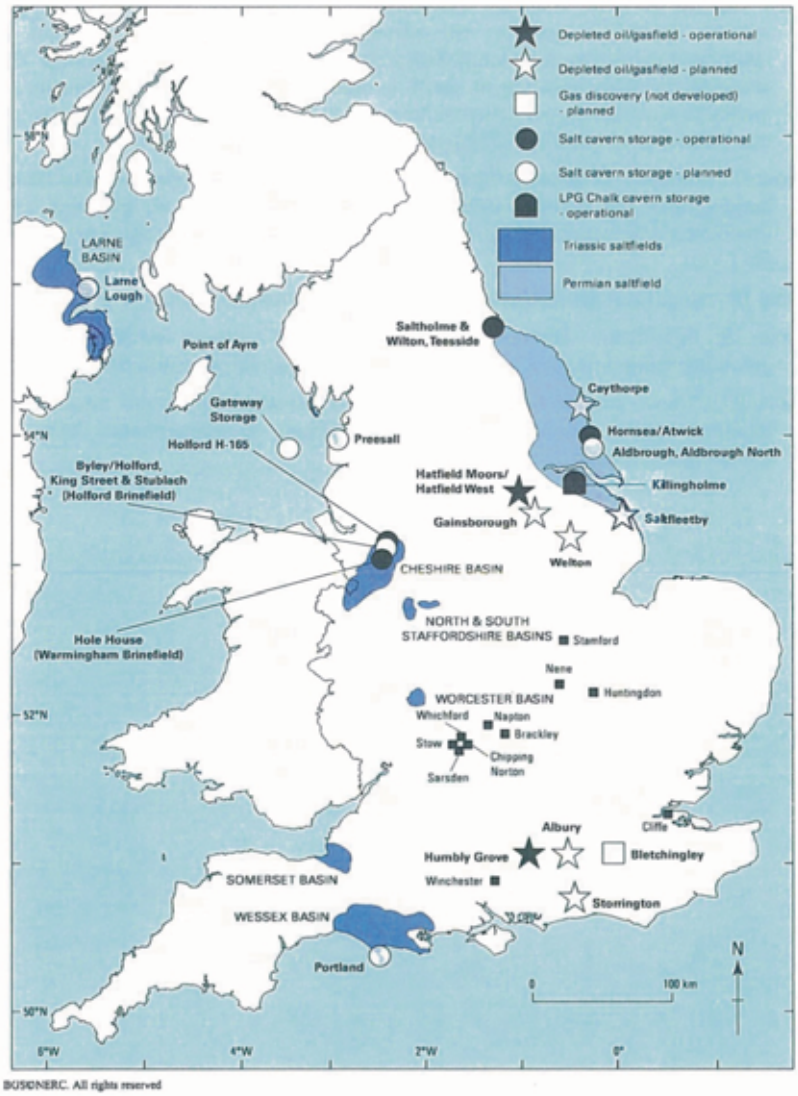
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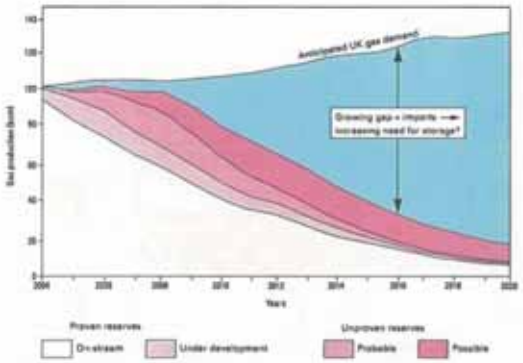
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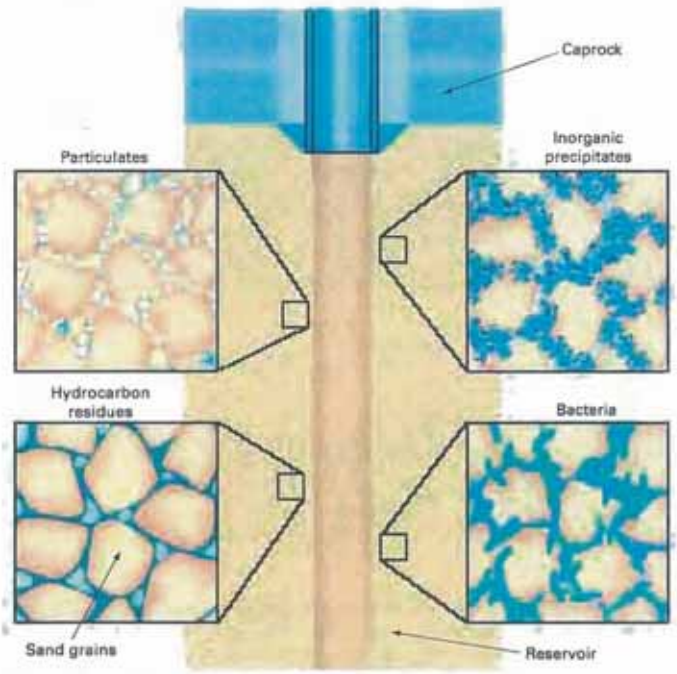
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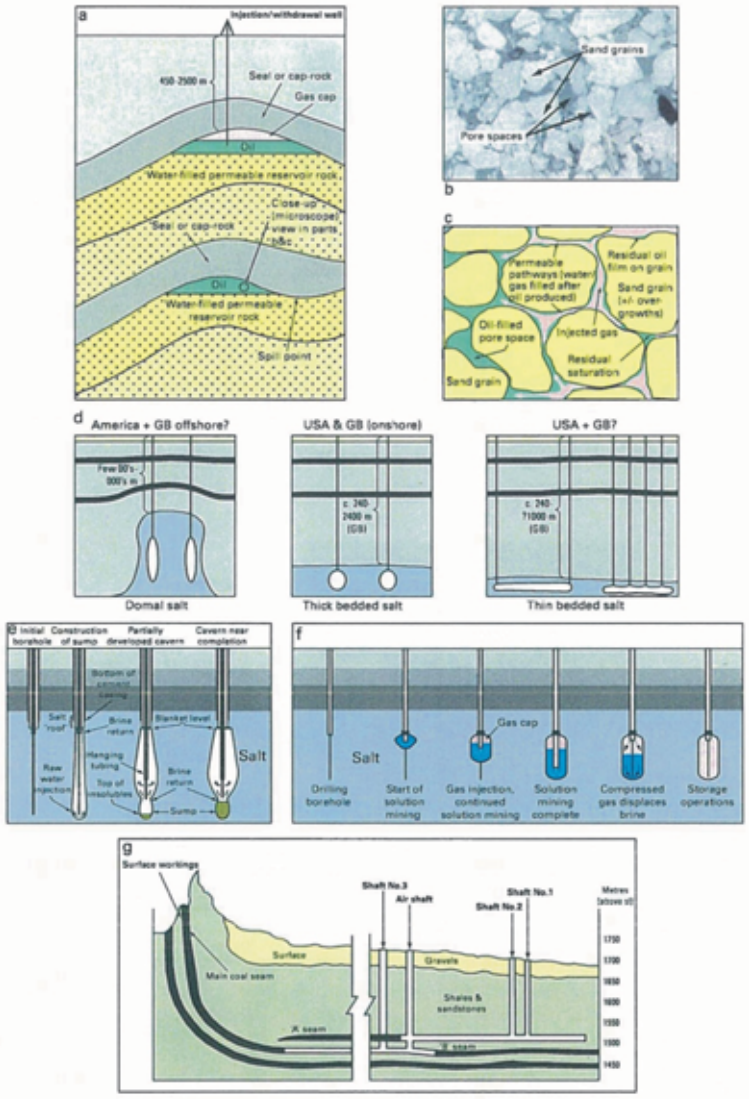
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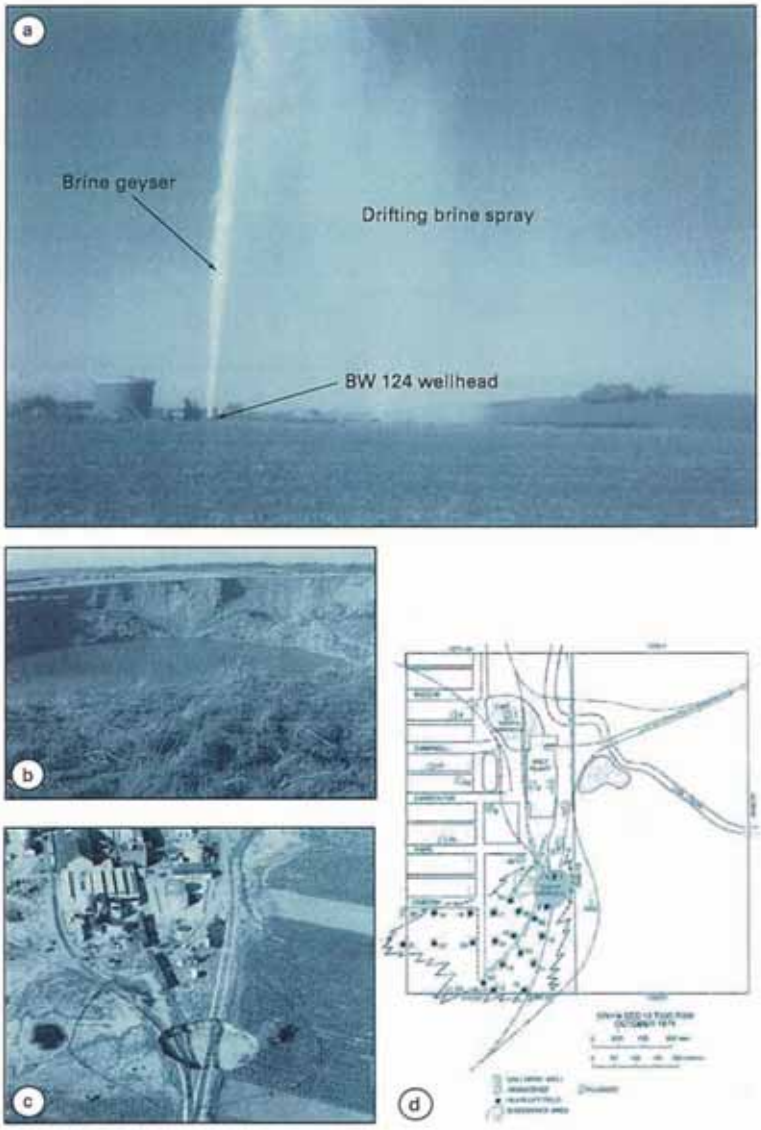
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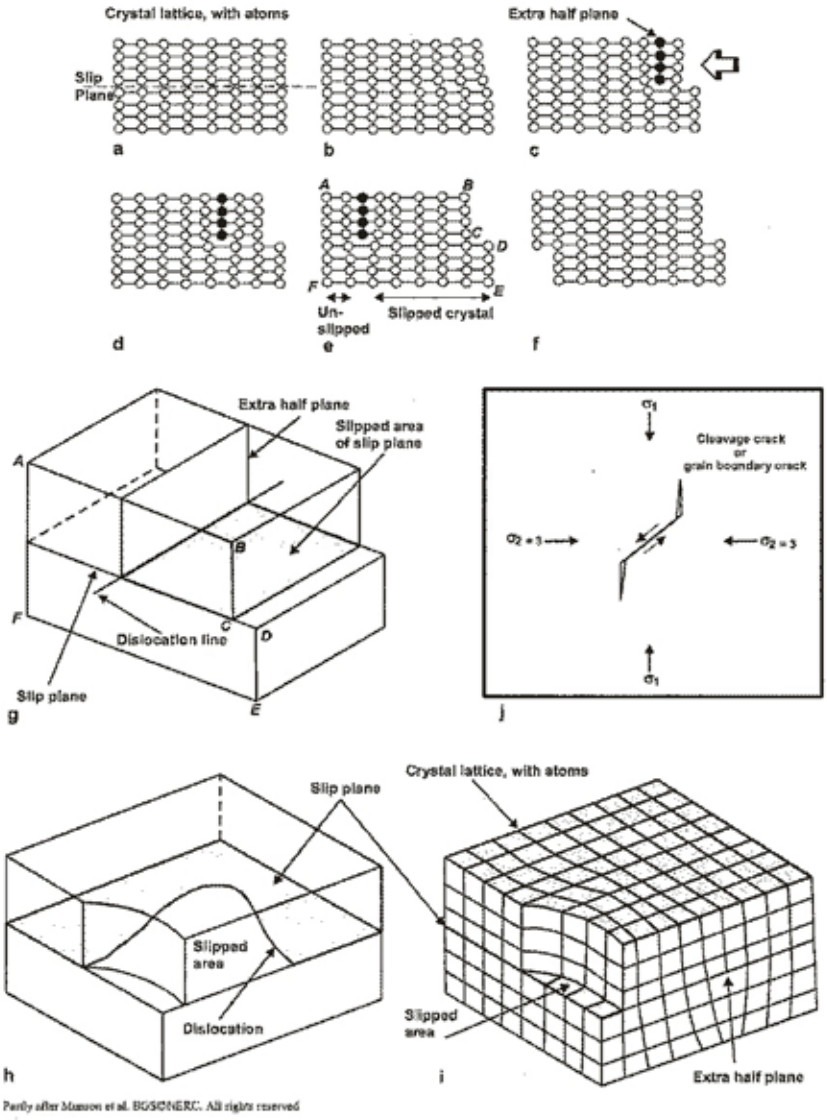
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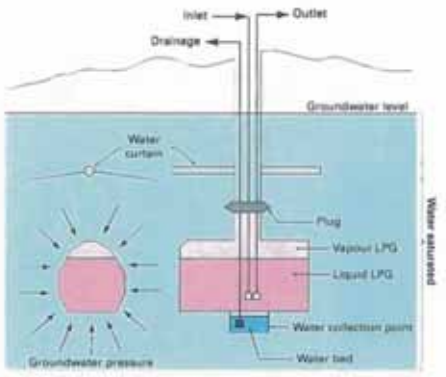
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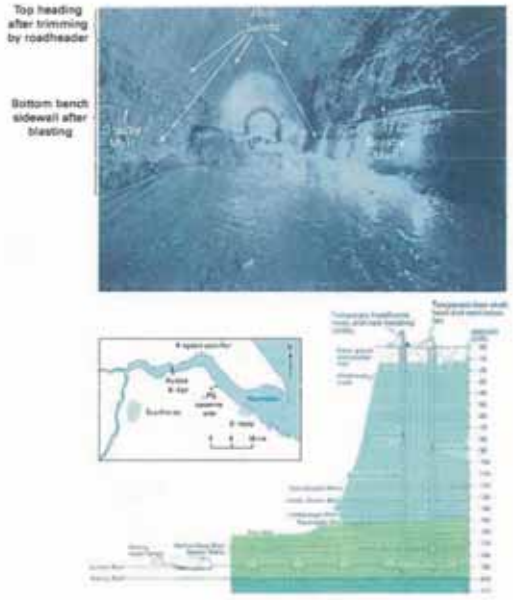
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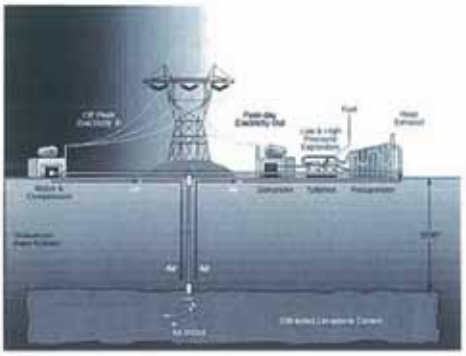
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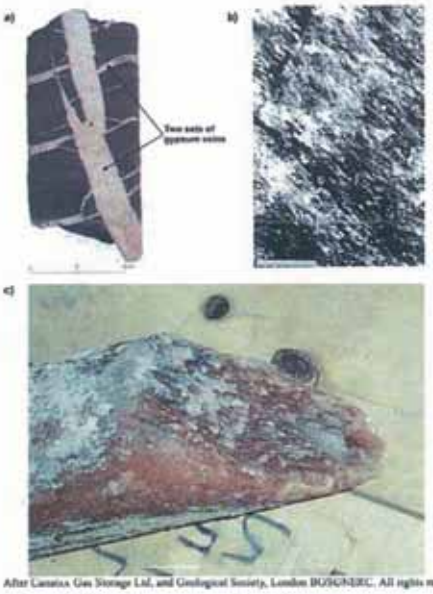
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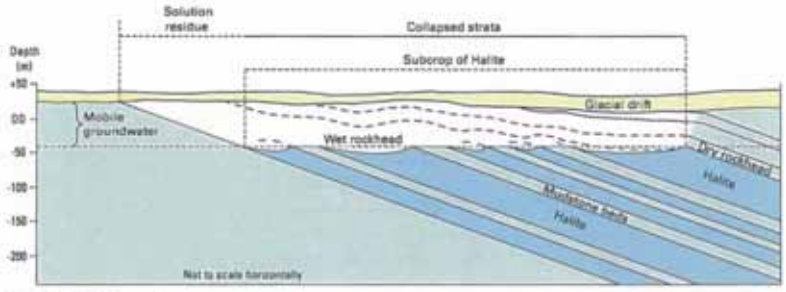
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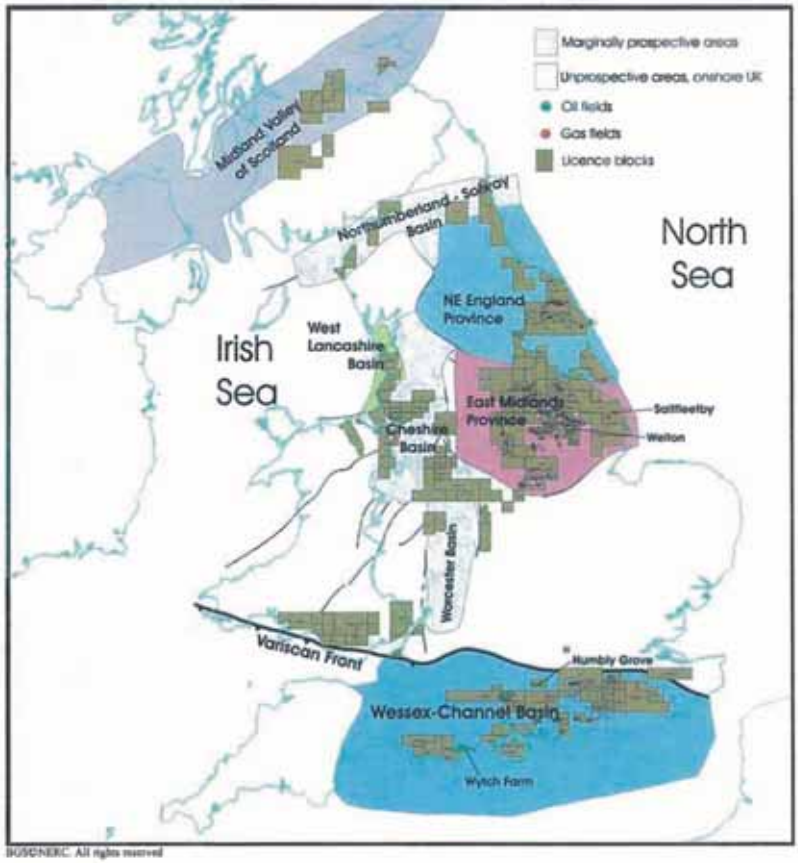
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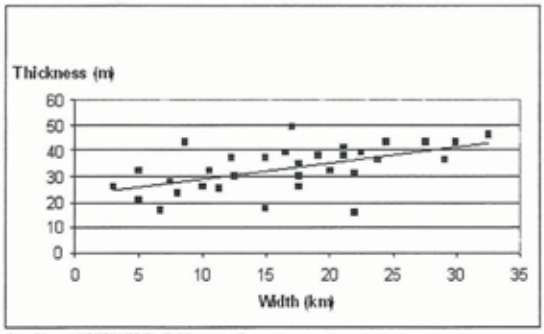
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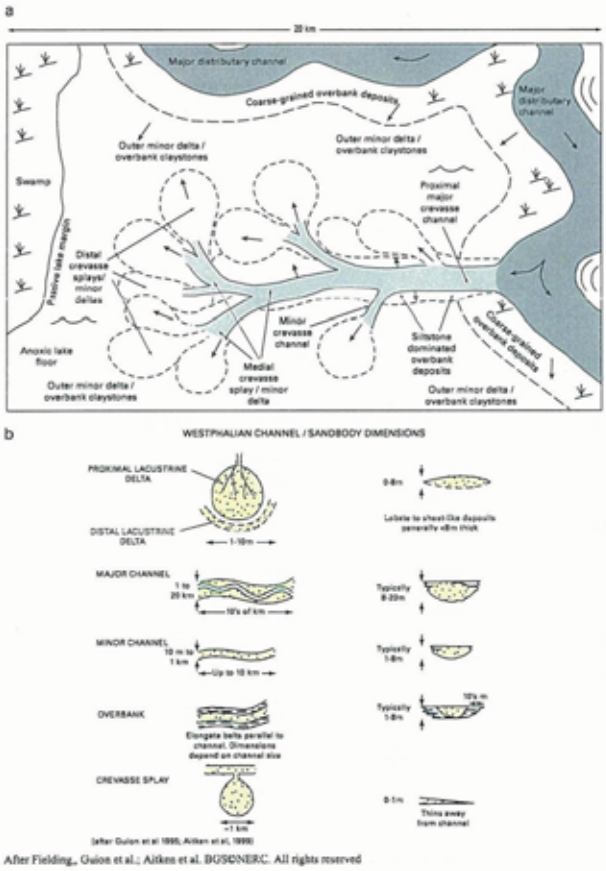
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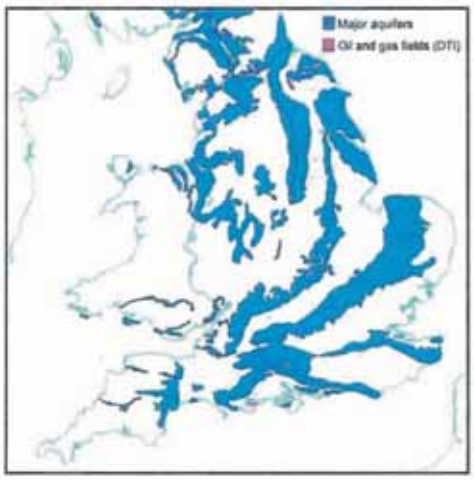
Figure 13. Westphalian channel width/thickness data (after Aitken et al., 1999).



After Fielding, Guion et al.; Aitken et al. BGSØNERC. All rights reserved

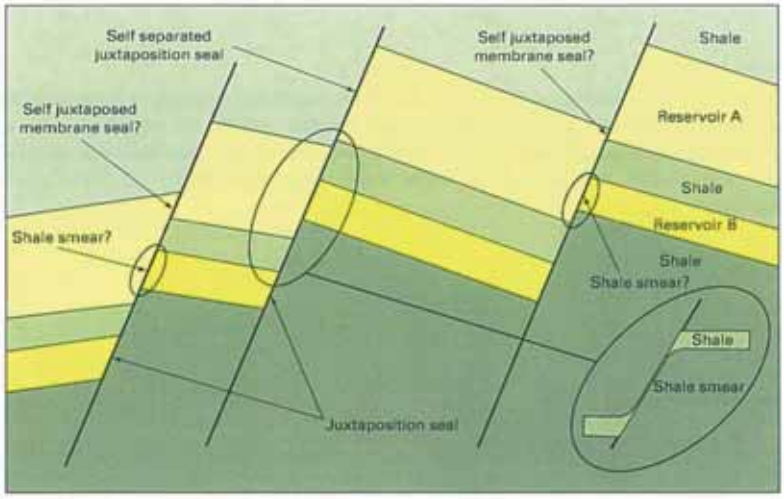
Figure 14. Westphalian depositional environments, with typical sand channel forms and dimensions (based upon Fielding, 1984; Guion et al., 1995; Aitken et al., 1999).

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Figure 15. Major aquifers cropping out in England and Wales (courtesy of Jennifer Cunningham, BGS Wallingford). Also shown, the relationship of major aquifers to the onshore oil and gasfields.



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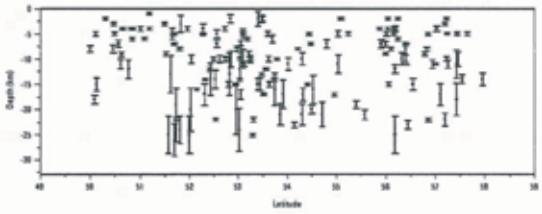
Figure 16. Schematic illustration of faulted sand-shale sequence and terminology of fault offsets and sealing configurations referred to in the text (after Færseth, 2006). Where reservoir A and reservoir B are juxtaposed across faults, the shale interval stratigraphically between the two reservoir units may be smeared along the fault to form a seal that hydraulically separates the sandstones.

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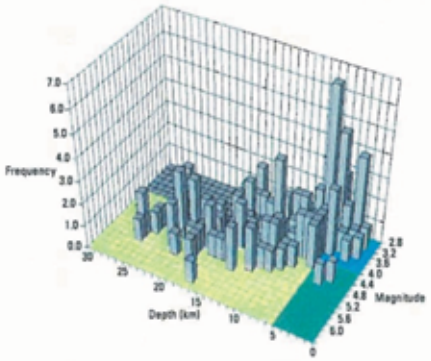
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Figure 17. Sketch map of the felt area of the Dogger Bank (7/6/31), Lleyn Peninsular (19/7/84) and Roermund (Netherlands, 13/4/92) earthquakes (from Browitt & Musson, 1993).



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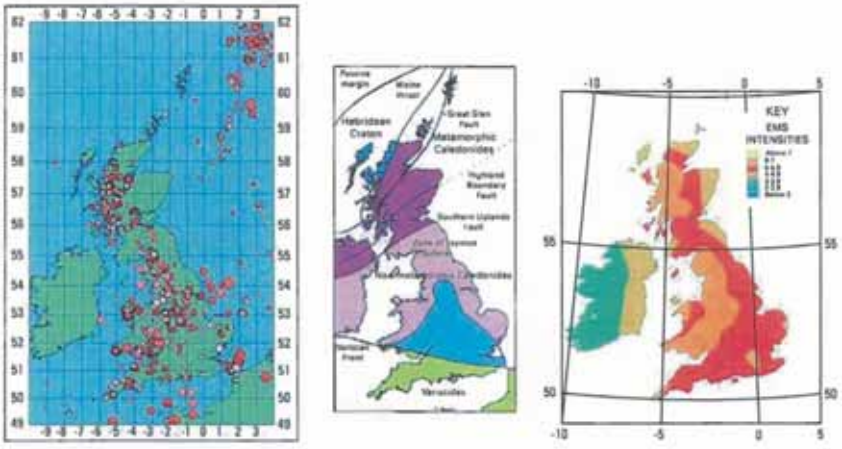
Figure 18. Cross section of UK seismicity from south to north plotted by latitude and depth, showing probable maximum vertical extent of ruptures for all earthquakes with magnitude > 3 M_L with known depths in mainland UK and the Irish Sea. Refer section 6.2 of main report for description of earthquake magnitudes (M_L).



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Figure 19. Numbers of UK earthquakes classed by magnitude and depth.

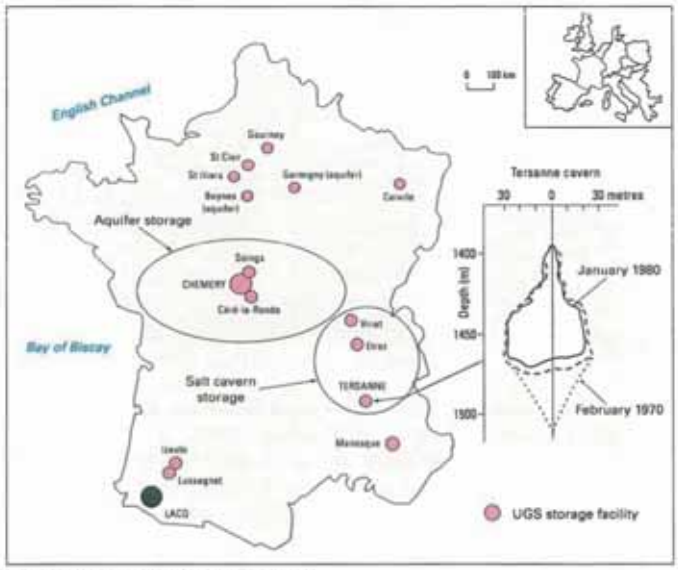
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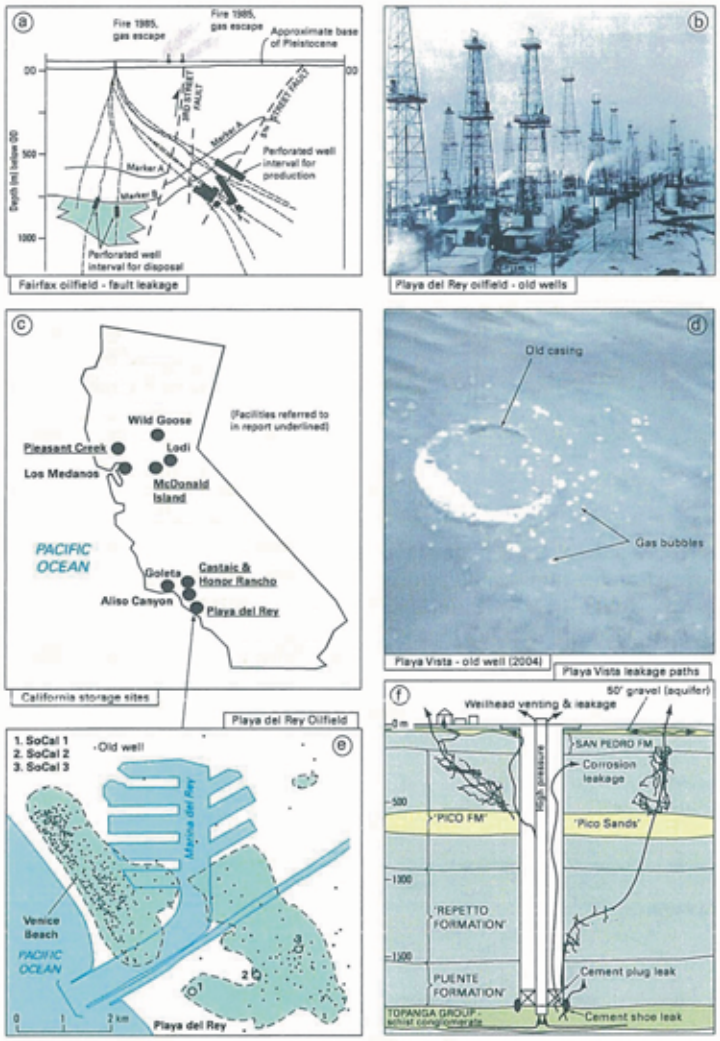
Figure 20. UK seismicity maps (from Musson, 2003b: http://www.earthquakes.bgs.ac.uk/hazard/Hazard_UK.htm). a) earthquakes in the UK, b) tectonic sketch map of the UK, c) EMS intensity hazard map for the UK.



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Figure 21. Location of French UGS sites referred to in the text and details of the Tersanne cavern dimensions prior to and following salt creep (after Bérest & Brouard, 2003).

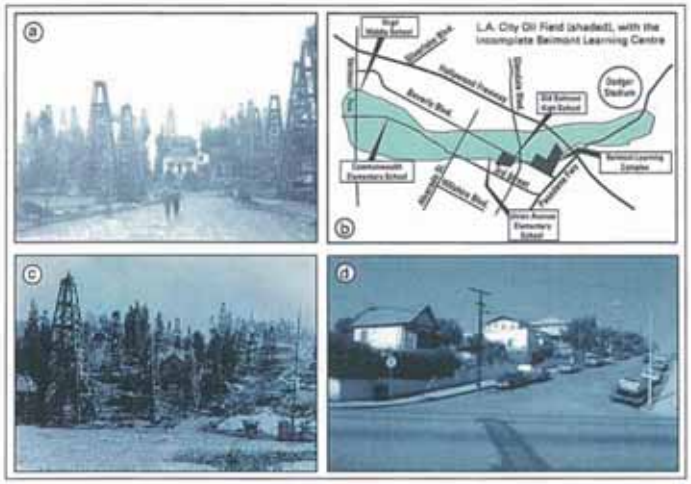
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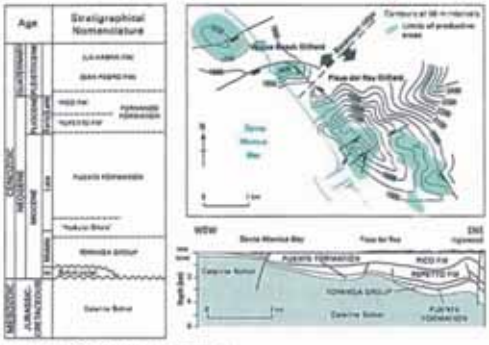
Figure 22. Details of Californian oilfields. a) cross section of the leakage scenario at the Fairfax Oilfield (after Hamilton & Meehan, 1992), b) skyline of oil derricks at the Playa del Rey Oilfield (after Seaver Center for Western History Research, Los Angeles County Museum of Natural History), c) general location map of depleted gasfields and gas storage sites in California and referred to in the text, d) gas bubbling up old leaking well in shallow water pond, Playa del Rey (courtesy Jeanette Vosberg, Save Ballona Wetlands. See http://saveballona.org/techpages/well.html), e) map of the Playa del Rey and Venice Beach oilfields with known well locations, f) schematic section of Playa del Rey Oilfield showing gas leakage paths.

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After California Division of Oil, Gas and Geothermal Resources, Seaver Center for Western History Research, Los Angeles County Museum of Natural History California History Room, California State Library, Sacramento, California BGS©NERC. All rights reserved

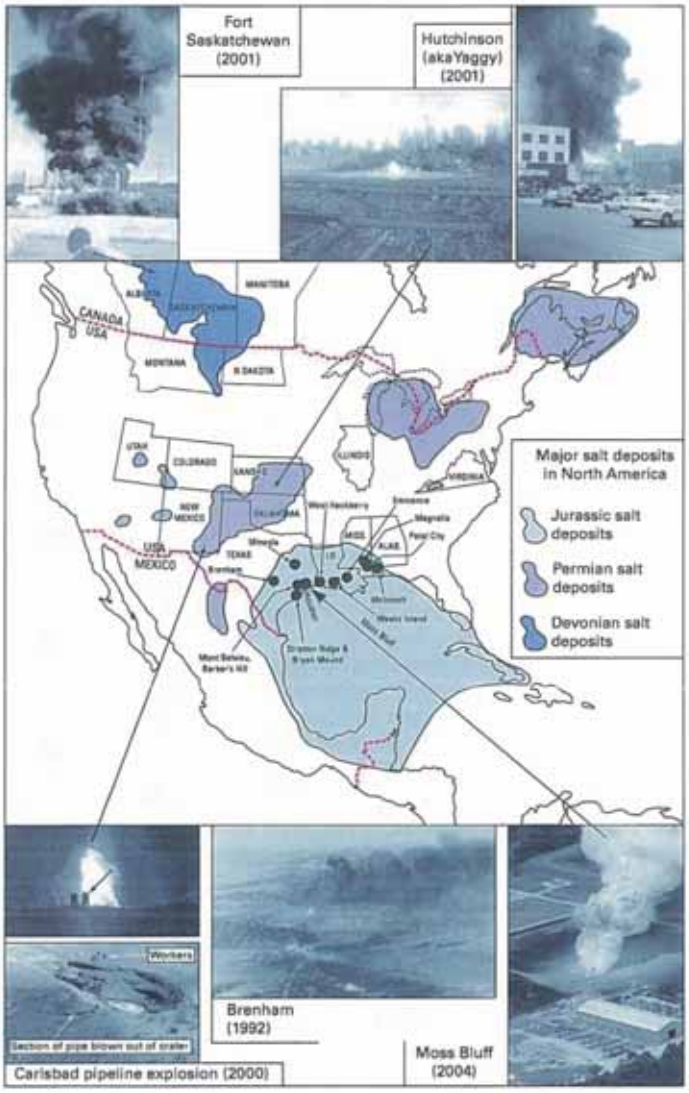
Figure 23. Illustrations of former heavily drilled areas of Los Angeles that are now densely populated urban areas. a) view of oil derricks associated with the Los Angeles City Oilfield (.c 1890; courtesy of Lena Tabilio and the California Division of Oil, Gas and Geothermal Resources. (http://www.consrv.ca.gov/index/siteMap.htm#doggr), b) map of the Belmont School area, where construction stopped due to the underlying LA City Oilfield, c) Los Angeles City Oilfield at the corner of Glendale Boulevard and Rockwood Street, circa 1900 (Photo courtesy of the Seaver Center for Western History Research, Los Angeles County Museum of Natural History, www.nhm.org), and d) Los Angeles City Oilfield at the corner of Glendale Boulevard and Rockwood Street, October 2002 (from Gamache & Frost, 2003; courtesy of the California History Room, California State Library, Sacramento, California (www.library.ca.gov/calhist/index.html).



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Figure 24. Stratigraphy of the Los Angeles area, structure contour map (at near top basement) of the Venice Beach and Playa del Rey oilfields and cross section of the Playa del Rey Oilfield (based upon Wright, 1991).

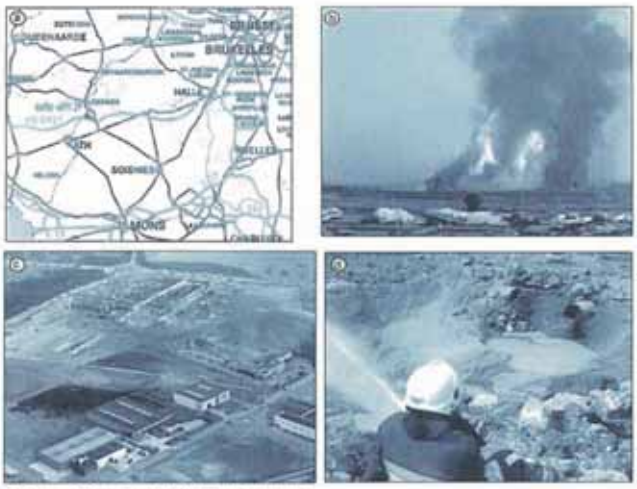
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After Hutchinson Fire Brigade, CUDD Drilling and Shannon Pope of RPC Inc, Dave Ryan, NTSB and Liz Nayowski, Fort Saskatchewan Record DGSDNERC. All rights reserved

Figure 25. **Major salt basins of the North America, including the main salt domes referred to in the text. Also shown, images of the major gas release incidents at Hutchinson (downtown fire, courtesy Chief Forbes, Hutchinson Fire Brigade; gas geyser, CUDD Drilling and Shannon Pope of RPC Inc), Moss Bluff (after Dave Ryan, Beaumont Enterprises http://www.thefortressweb.com), Brenham (courtesy of NTSB, 1993), Fort Saskatchewan (after Liz Nayowski, Fort Saskatchewan Record: http://www.chem.queensu.ca/chembook/articles/ethane_fire_in_fort_saskatchewan.htm), night time image of the Carlsbad pipeline incident which caused a crater 15.5 m by 34.5 m, bridge towers (estimated 10 m high) arrowed for scale (courtesy of NTSB, 2003).**

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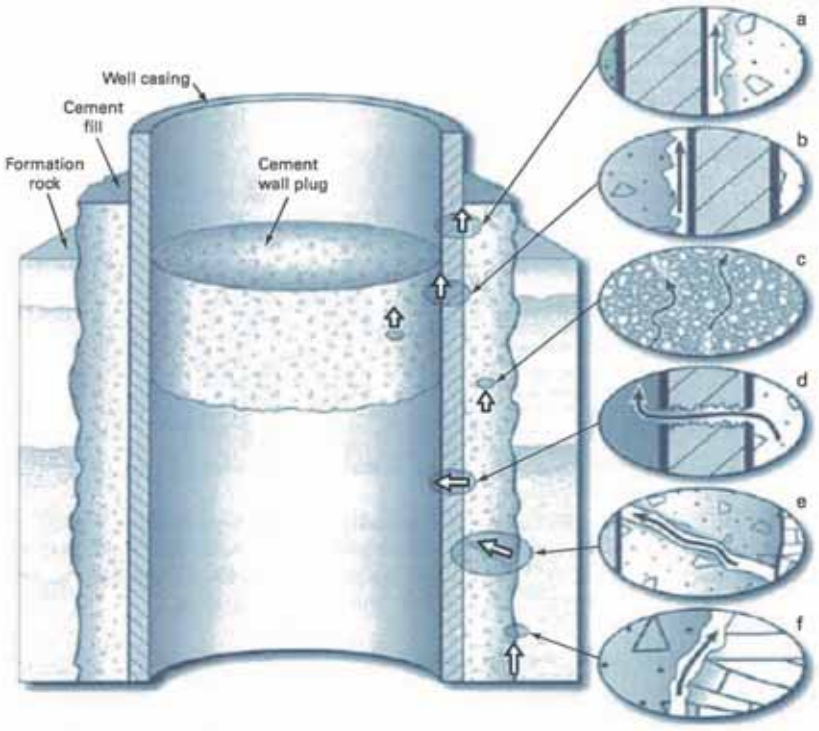
Figure 26. The Ghislenghien gas pipeline explosion (images courtesy Emergency Management: http://www.emergency-management.net/gaspipeline2004.htm). a) location map, b) the fire following the explosion, c) view of the general site showing the burned area and d) the crater and exposed pipeline.



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Figure 27. The 2005 Buncefield above ground storage incident (after Powell 2006a&b). a) aerial view of the site prior to the incident, b) the incident from the air, c) aerial view of damage to storage vessels, d) map illustrating the proximity of the storage depot to surrounding industrial and domestic buildings.

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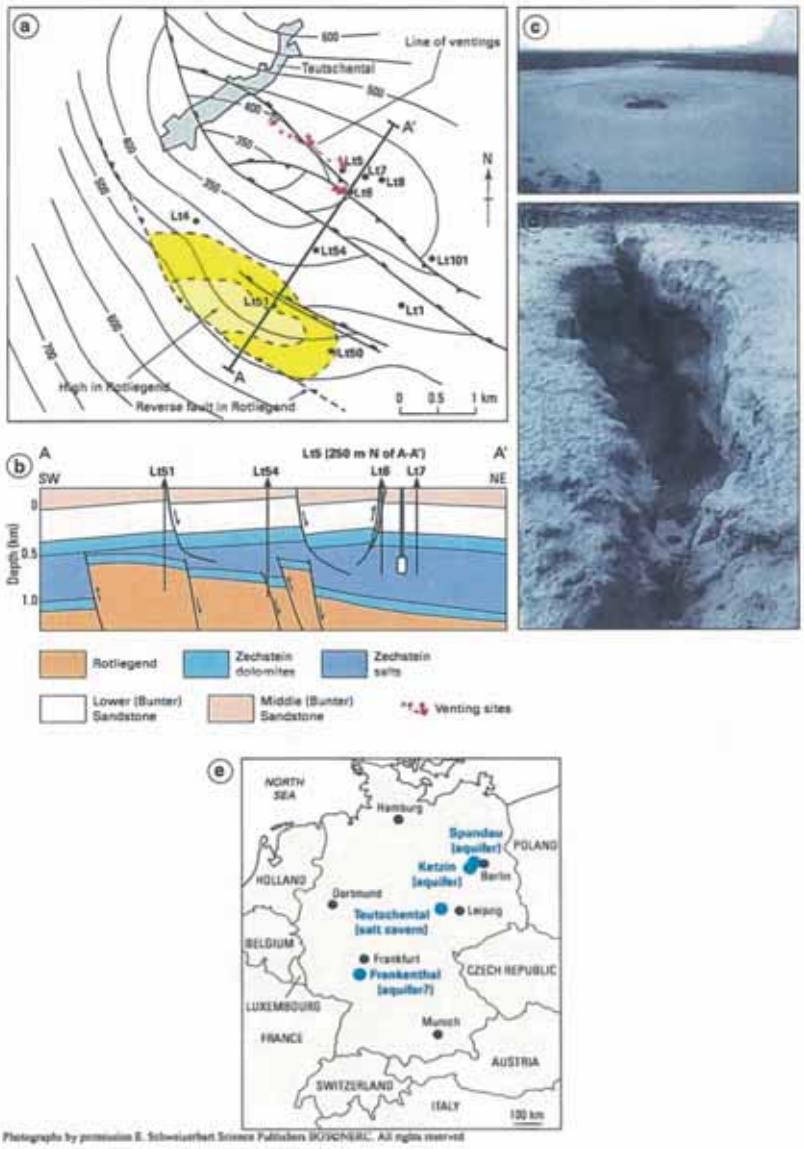
Figure 28. Schematic illustration of possible leakage pathways through an abandoned well: a) between casing and cement, b) between cement plug and casing, c) through the cement pore space due to cement degradation, d) through well casing as a result of corrosion, e) through fractures in cement, f) between cement and rock. (Figure from Scherer et al., 2005; reproduced from Environmental Geology, by permission of ©Springer Verlag).



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Figure 29 Humbly Grove gas storage facility (courtesy Star Energy). a) site clearance (Feb 2004) and b and c) completed facility (Feb 2005).

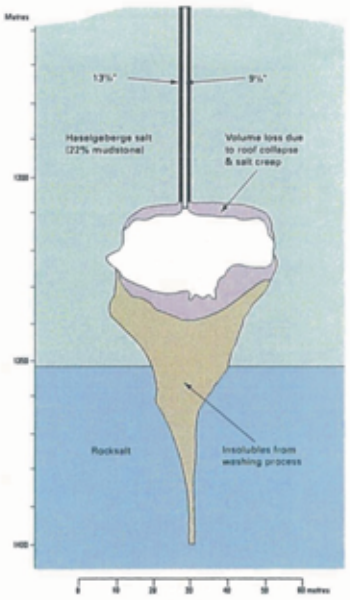
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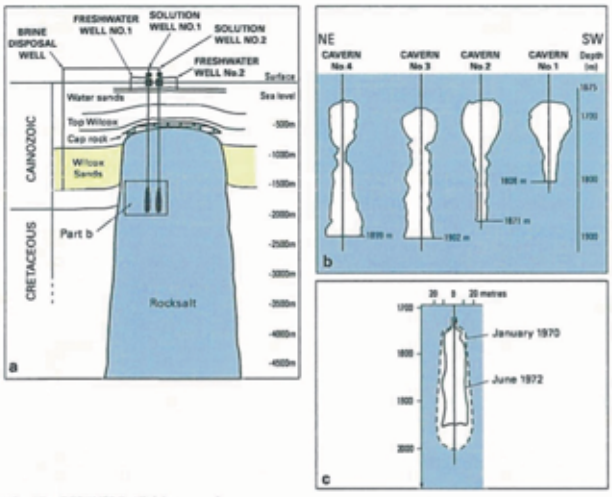
Figure 30. Details of the Teutschental (West Germany) site and ethylene escape (based upon Katzkung et al., 1996). a) structure contour map on top Zechstein halite, b) SW-NE cross section across the Lauchstädt structure and storage site area, c) and d) photographs of venting sites, from which a mixture of ethylene and water erupted, e) location map for UGS sites in Germany and referred to in text. Photographs reproduced by permission of E. Schweizerbart Science Publishers: http://www.schweizerbart.de/).

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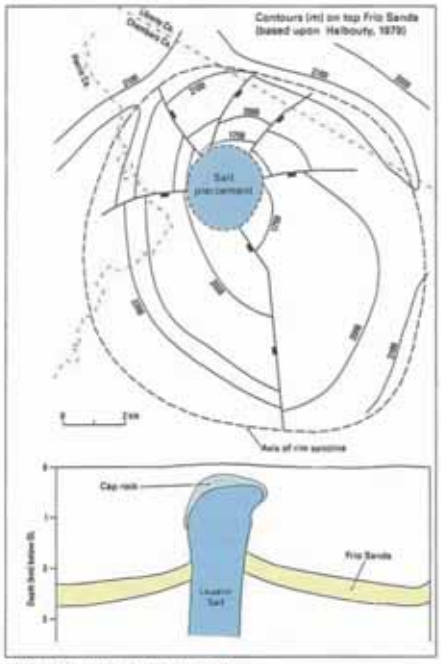
Figure 31. Detail of the Kiel storage cavern in Germany, illustrating volume loss due to insolubles, roof collapse and salt creep (after Bérest & Brouard, 2003).



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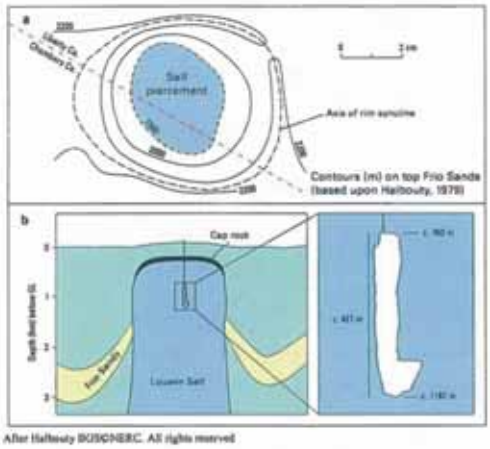
Figure 32. Details of the Eminence salt dome and storage facility (based upon Allen, 1972). a) cross-section of the salt dome with depth of caverns, b) detail of the depths and shapes of the four caverns constructed at Eminence c) illustration of the extent of salt creep and decrease in cavern size.

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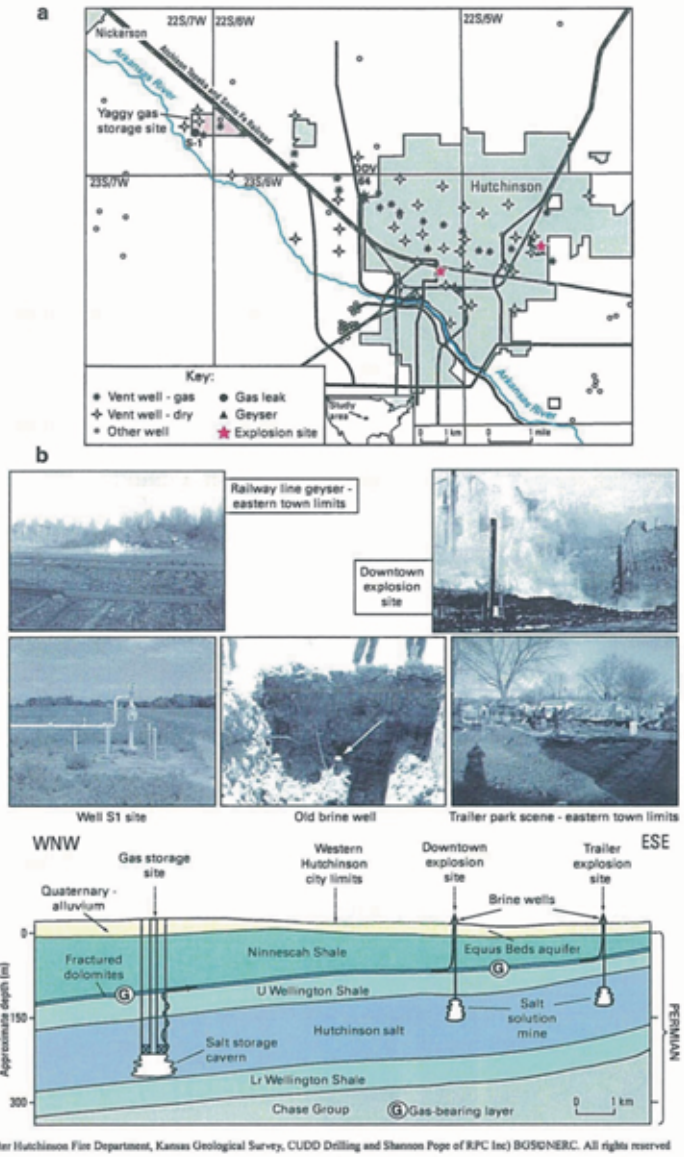
Figure 33. Details of the Mont Belvieu salt dome and storage facility a) structure contour map on the top of the Frio Sands showing area of salt piercement (after Halbouty, 1979), b) cross-section of the salt dome.



After Halbouty BOSDNERC. All rights reserved

Figure 34. Details of the Moss Bluff salt dome and storage facility a) structure contour map on the top of the Frio Sands showing area of salt piercement (after Halbouty, 1979), b) cross-section of the salt dome illustrating the depth of the cavern and shape.

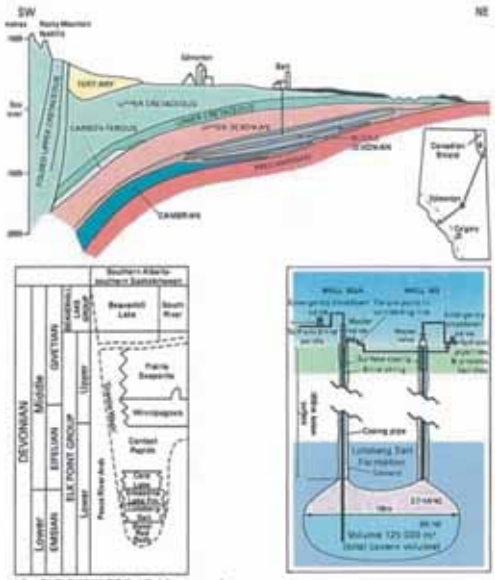
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After Hutchinson Fire Department, Kansas Geological Survey, CUDD Drilling and Shannon Pope of RPC Inc) BGS©NERC. All rights reserved

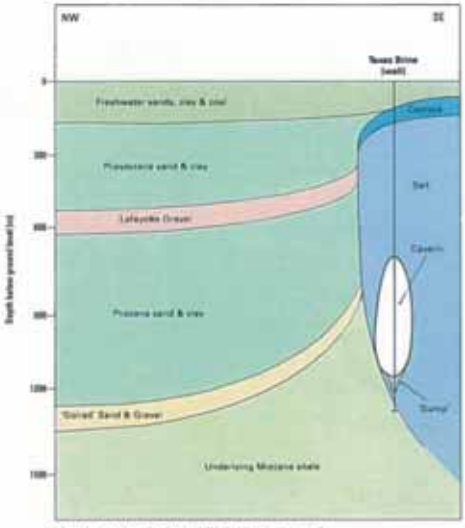
Figure 35. Details of the Hutchinson incident. (a) location map illustrating the site of the storage facility circa 11 km (7 miles) NW of the town of Hutchinson (b) WNW-ESE cross section showing the stratigraphy and structure of the area and the route taken by the gas from the storage cavern to the town (after Kansas Geological Survey). Images shown courtesy of Chief Forbes, Hutchinson Fire Department; Kansas Geological Survey; Kansas Department of Health and Environment, CUDD Drilling and Shannon Pope of RPC Inc.

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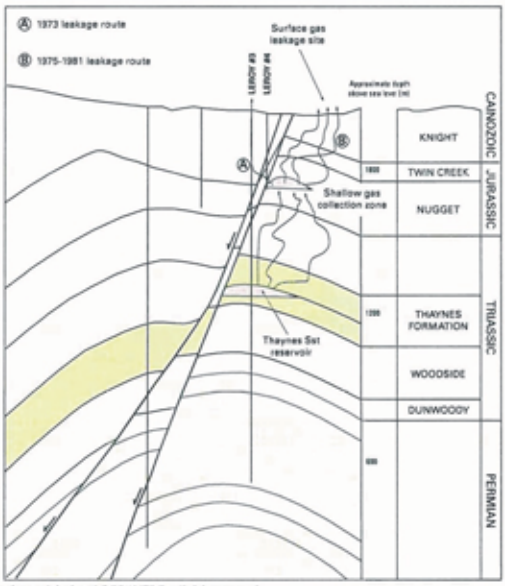
Figure 36. Setting of the Fort Saskatchewan cavern storage facility, Canada. a) sketch cross section of the area, b) cross section of the cavern an infra-structure (after EUB, 2002).



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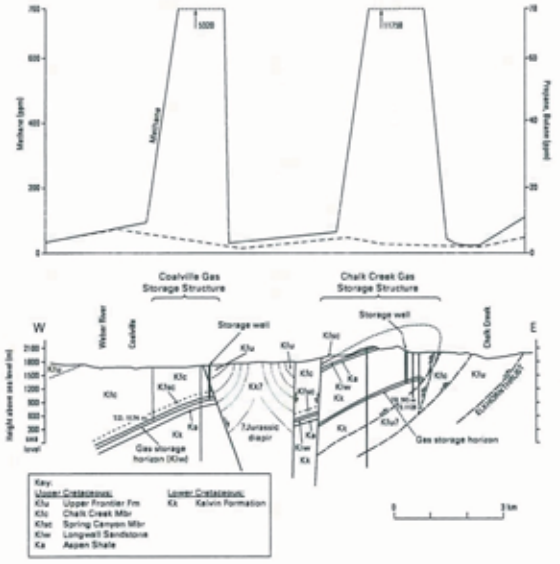
Figure 37. Sketch section through the Napoleanville salt dome illustrating the situation when shale layers were encountered indicating that due to poor site characterisation, the sidewalls of the salt dome/stock had been intersected during brining operations (after Neal & Magorian, 1997).

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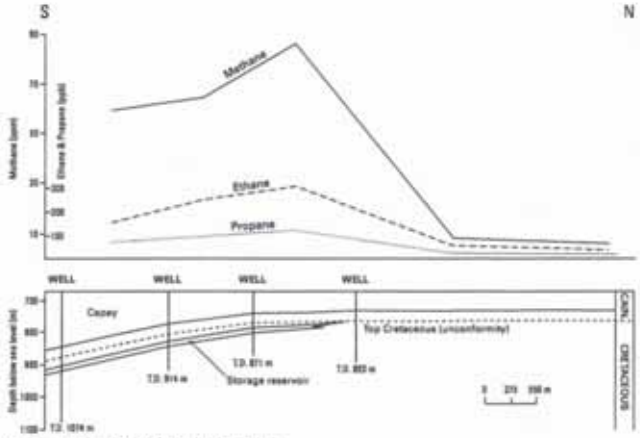
Figure 38. Stratigraphy, cross-section and leakage paths from the Leroy Gas Storage Facility, Wyoming (after Araktingi et al., 1984).



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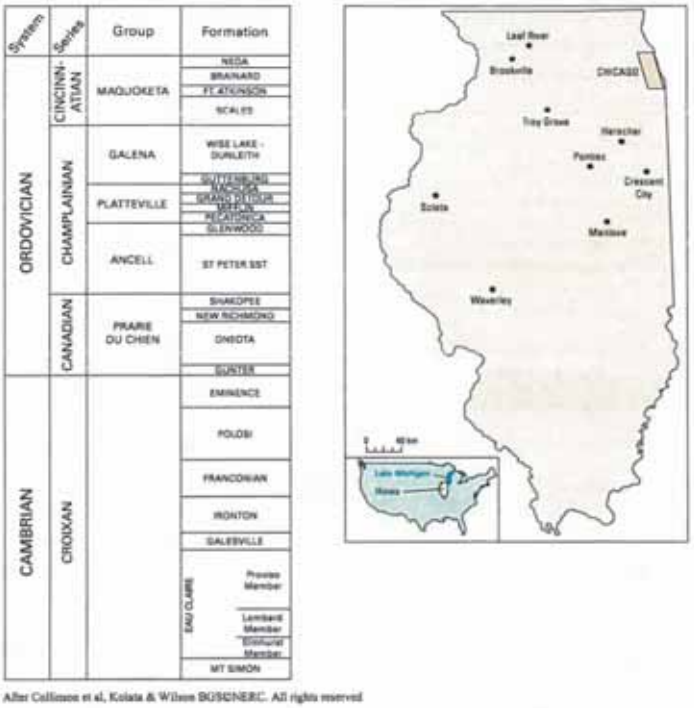
Figure 39. Stratigraphy and structural detail of the Coalville and Chalk Creek gas (aquifer) storage facilities, Utah, USA (after Morgan, 2004).

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Figure 40. Cross-section of the Pleasant Creek gas (aquifer) storage facility in California (after Jones & Drozd, 1983). Also shown the soil-gas profiles showing leakage of the aquifer caprock.



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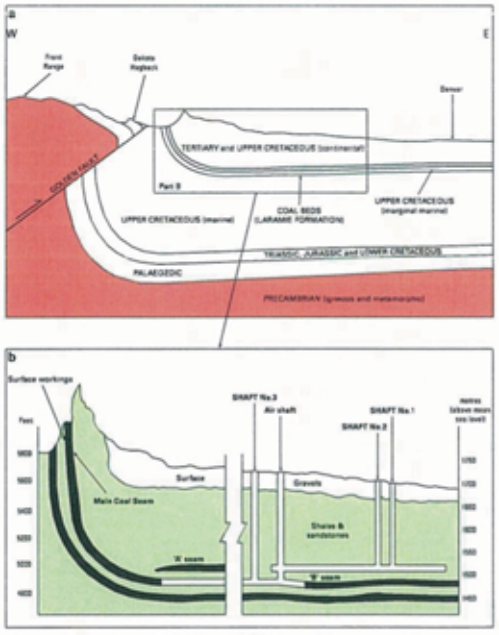
Figure 41. Stratigraphy of Illinois aquifer sandstones and location of the main gas storage sites having experienced difficulties, see Appendix 5 (after Collinson et al., 1988; Kolata & Wilson, 1991).

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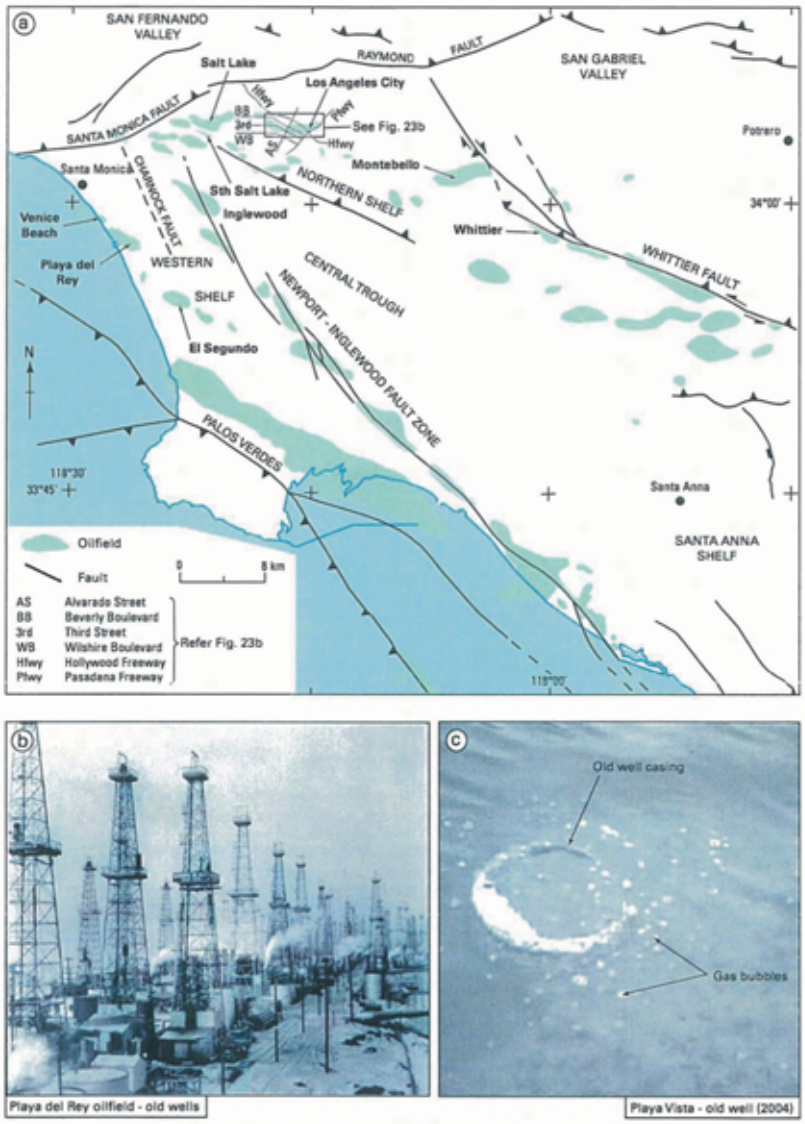
Figure 42. Structural contour map of the Weeks Island salt dome, Louisiana, illustrating the sites of the two sink holes in relation to the extent of salt mine workings (after Warren, 2006).



After Raven Ridge Resources BGS©NERC. All rights reserved

Figure 43. Detail of the Leyden Mine gas storage site, Colorado (after Raven Ridge Resources, 1998).

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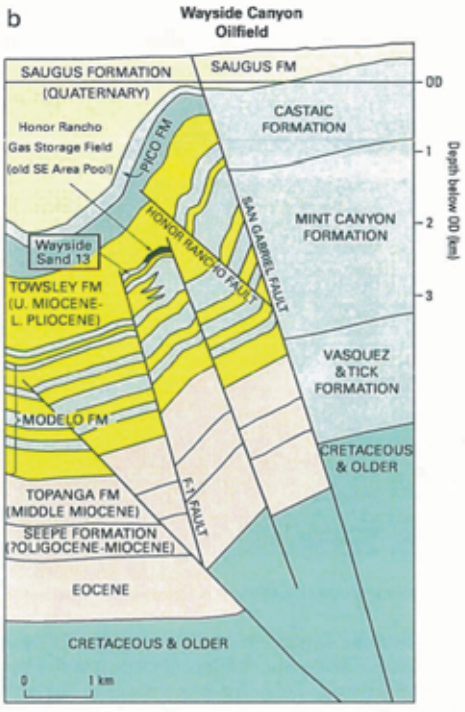


After Seaver Center for Western History Research, Los Angeles County Museum of Natural History Save Ballona Wetlands, Camp Dresser & McKee, Wright and Biddle BGSC©NERC. All rights reserved

Figure 44. Map of the oilfields and main tectonic features in the Los Angeles Basin. a) Oilfields based upon Camp Dresser & McKee (2001) and Wright (1991), faults based upon Wright (1991) and Biddle (1991), b) oil derricks along the ocean front at Playa del Rey (after Seaver Center for Western History Research, Los Angeles County Museum of Natural History), c) gas bubbles emerging from old oil well in lagoon at Playa Vista, Playa del Rey oilfield (courtesy Jeanette Vosberg, Save Ballona Wetlands - see http://saveballona.org/techpages/well.html).

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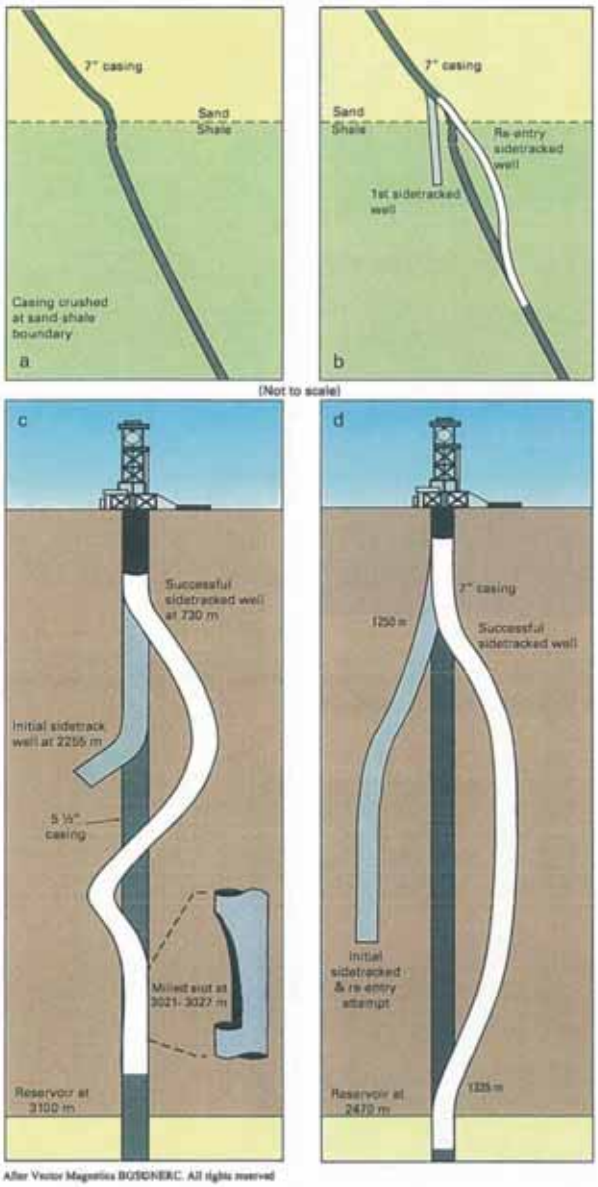




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Figure 45. Castaic and Honor Rancho gas storage facilities. a) Location map, b) cross section of the Honor Rancho Oilfield (after Davis & Namson, 2004).

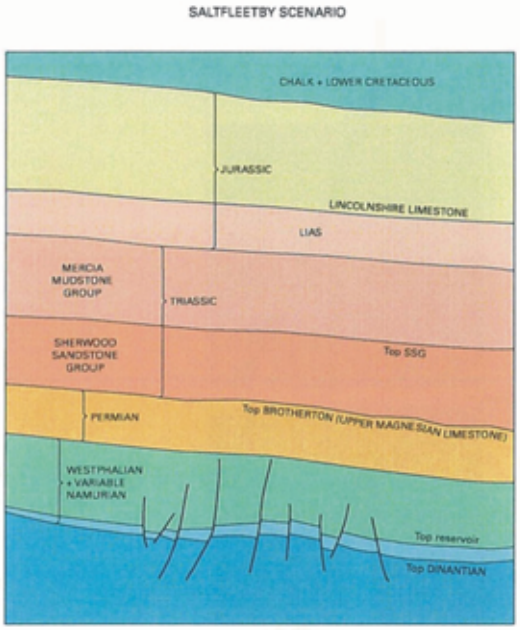
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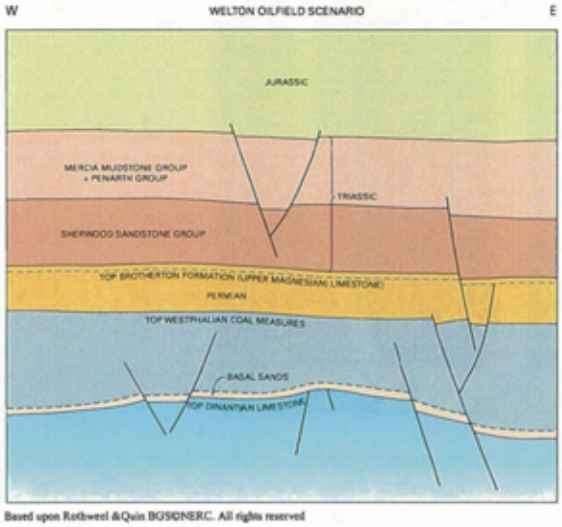
Figure 46. Sketch diagrams showing problems with and the repair of gas storage wells in California (after Vector Magnetics: http://www.vectormagnetics.com/ Case_HistoryO&G.html). a) and b) damage following an earthquake, c) inadvertent sidetracking of a well, d) inadvertent sidetrack due to corroded casing.

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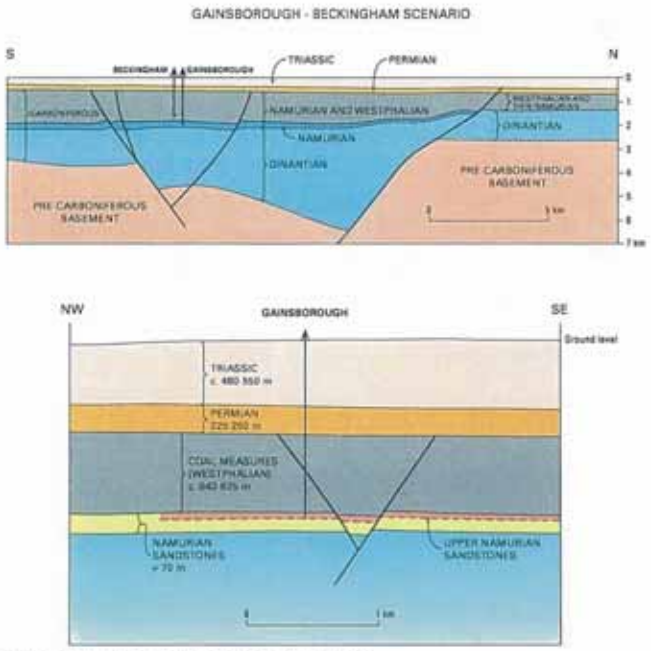
Figure 47. Sketch section illustrating the geological conditions likely to represent the 'Saltfleetby scenario' (based upon Hodge, 2003).



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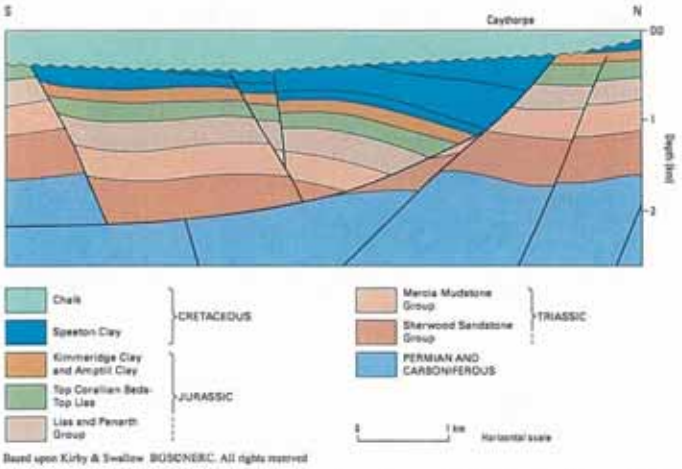
Figure 48. Sketch section illustrating the geological conditions likely to represent the 'Welton scenario' (based upon Rothwell & Quinn, 1987).

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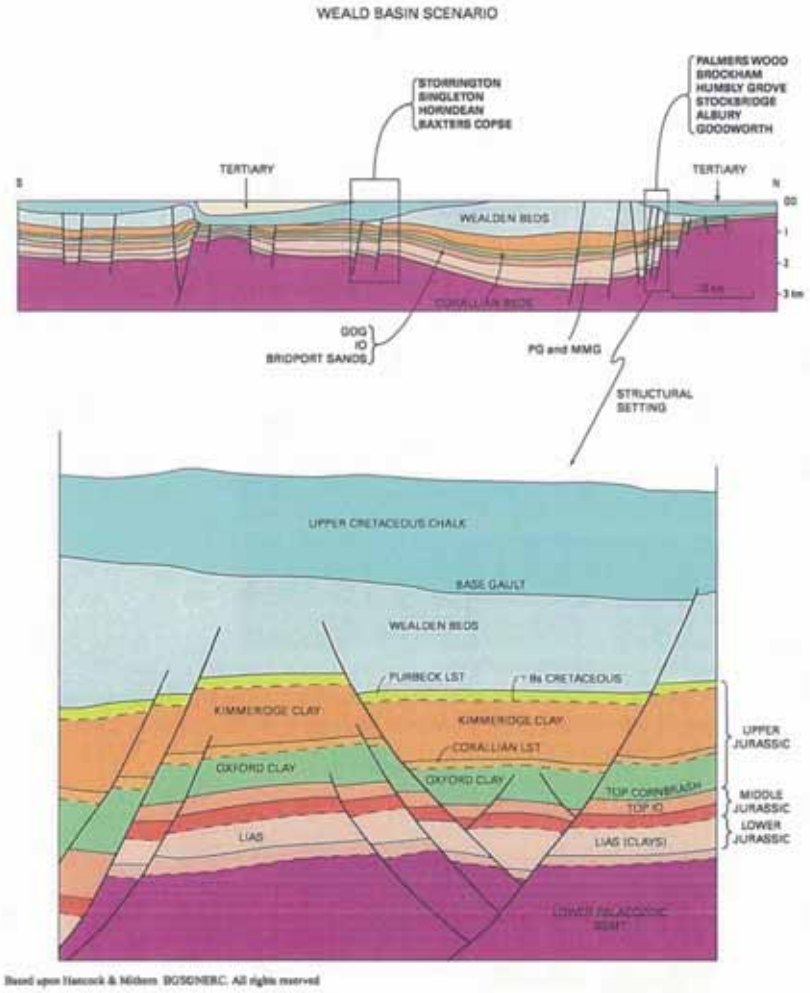
Figure 49. Sketch section illustrating the geological conditions likely to represent the 'Gainsborough-Beckingham scenario' (based upon Brunstrom, 1963; Fraser & Gawthorpe, 1990, 2003).



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Figure 50. Sketch section illustrating the geological conditions likely to represent the 'NE England scenarios' (e.g. Caythorpe and Kirby Misperton gasfields – based upon Kirby & Swallow, 1987).

D2-253 (Cont.)



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Figure 51. Sketch section illustrating the geological conditions likely to represent the 'Weald Basin scenarios' (e.g. Humbly Grove and Storrington – based upon Hancock & Mithern, 1987).

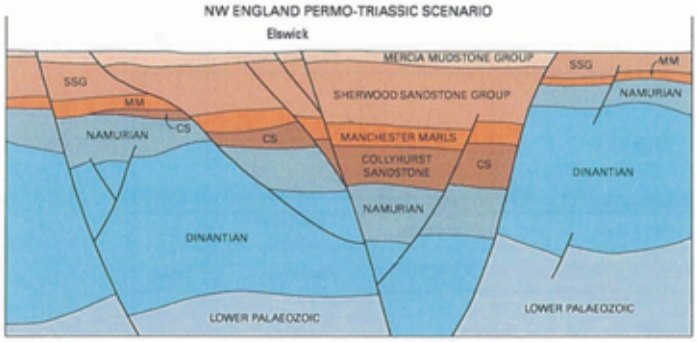
D2-253
(Cont.)

Age	Lithostratigraphy	Main rock type	Strength/Av. Porosity(%)	Approx. thickness (m)
Upper Cretaceous	Chalk	Chalky limestone	Moderately weak/ 10	183-213
	Upper Greensand	Sand		~30
	Gault Clay	Claystone	Weak rock 30-60	~75
Lower Cretaceous	Lower Greensand	Ferruginous sst	Weak rock	75-92
	Wealden	Sandstones and claystones	Moderately weak	192-232
	Purbeck	Siltstones, claystones, limestones	Weak rock	139-156
Upper Jurassic	Portland	Sst & siltst		52-62
	Kimmeridge Clay	Lsts,claystones siltstones	Weak rock/ 35	172-188
	Corallian	Sstn, marls claystones & silts		66-73
	Oxford Clay	Organic rich clays & silts	Weak rock/ 30	101-109
	Kellaways Beds	Fine sands & clays	Very weak rock/33	10-11
Middle Jur	Cornbrash Forest Marble & Gt Oolite Lst	Limestones & ssts	Weak to strong/ 9.6-16	60-70
	Fuller's Earth	Claystone, siltst	Very weak	17
	Inferior Oolite	Lst, clayst, siltst	Weak	30
Lower Jurassic	Upper Lias	Claystone	Weak	55
	Middle Lias	Siltst, fine sst	Weak/35	50
	Lower Lias	Organic rich claystones	Weak	~100
Rhaetic	Rhaetic Penarth Group	Lst, sst	Moderately strong	~10
Carb.	Carboniferous Limestone	Limestone		>10

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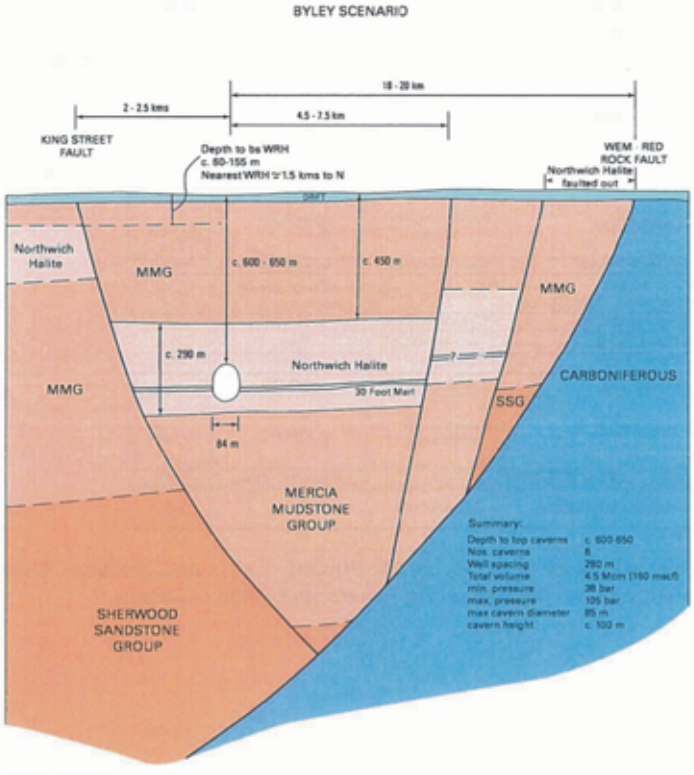
Figure 52. Generalised stratigraphy for the Humbly Grove and northern Weald area. Abbreviations: Lst –limestone; Sst – sandstone; Siltst - siltstone.

D2-253
(Cont.)



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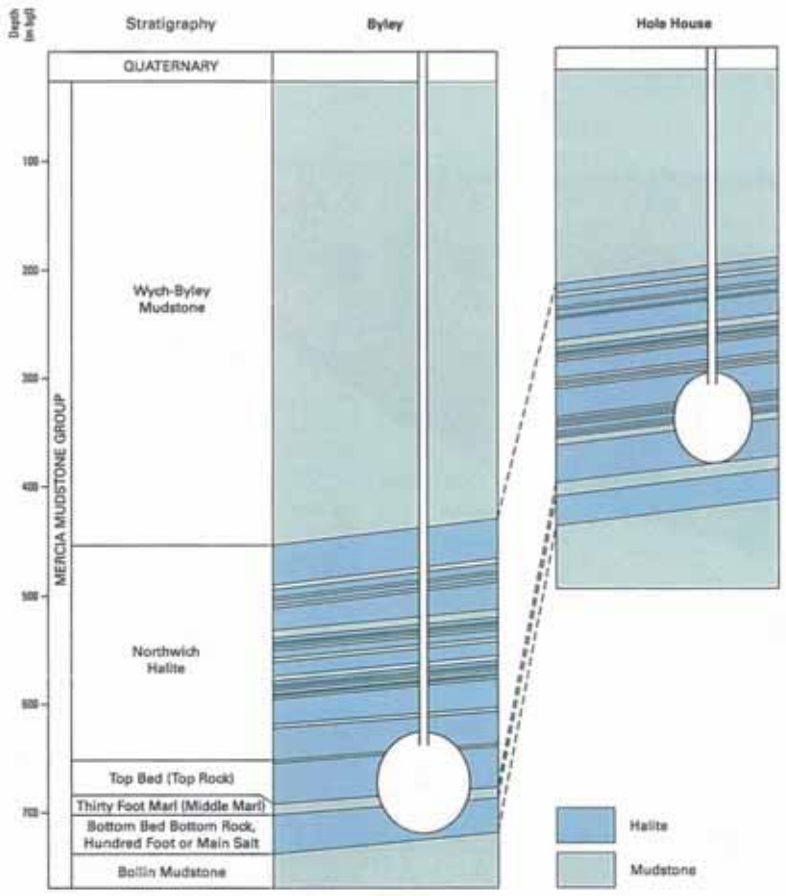
Figure 53. Sketch section illustrating the geological conditions likely to represent the 'NW England (Elswick) scenario' (based upon Aitkenhead et al., 1992).



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Figure 54. Sketch section illustrating the geological conditions likely to represent the 'Cheshire Basin scenario' – relating to the Byley, Hole House, King Street and Stublach sites.

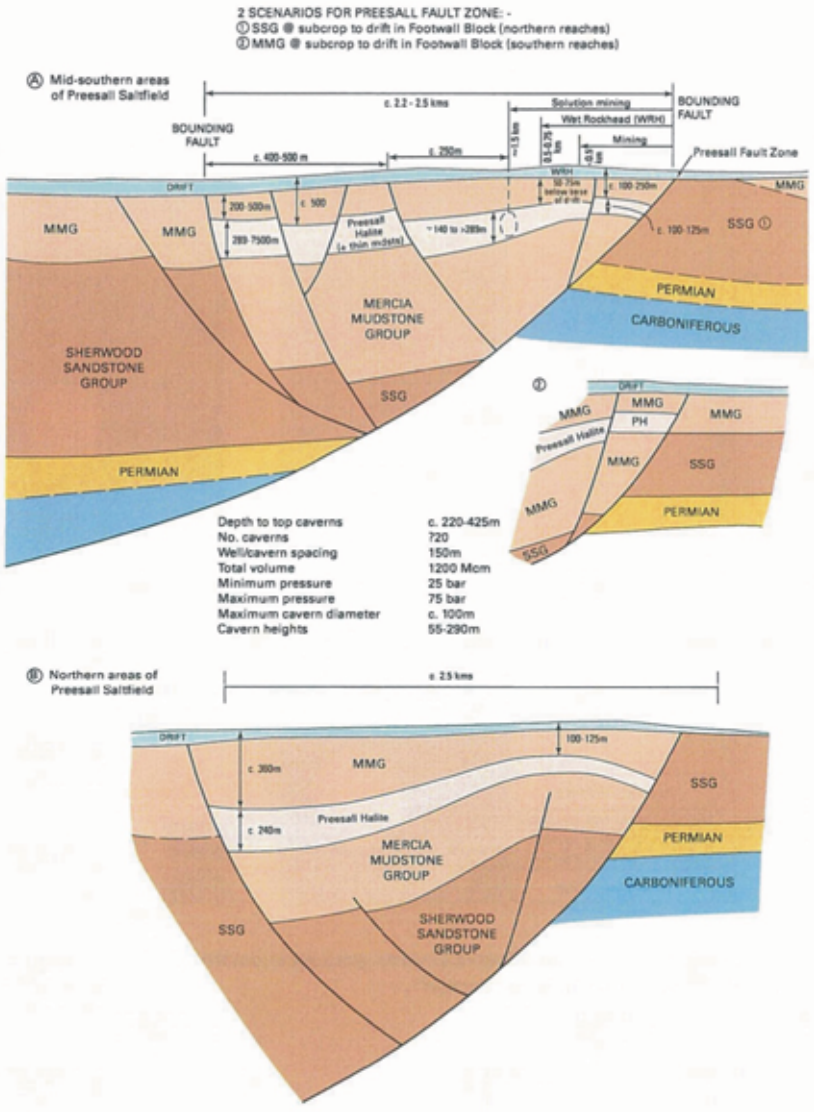
D2-253 (Cont.)



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Figure 55. Sketch section illustrating the geological conditions likely to represent the 'Byley and Hole House scenarios'.

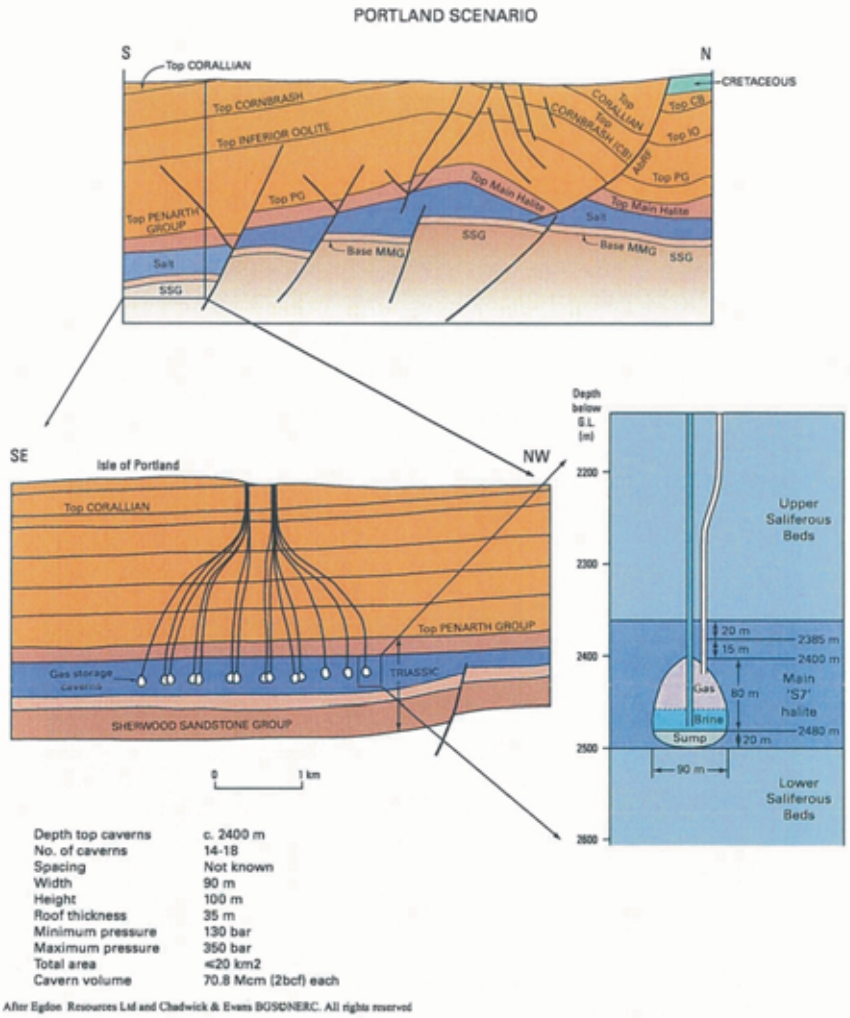
D2-253
(Cont.)



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Figure 56. Sketch section illustrating the geological conditions likely to represent the 'Preesall saltfield scenario'. a) the southern areas of the saltfield (more intragrabenal faults), b) the northern areas of the saltfield (fewer intragrabenal faults).

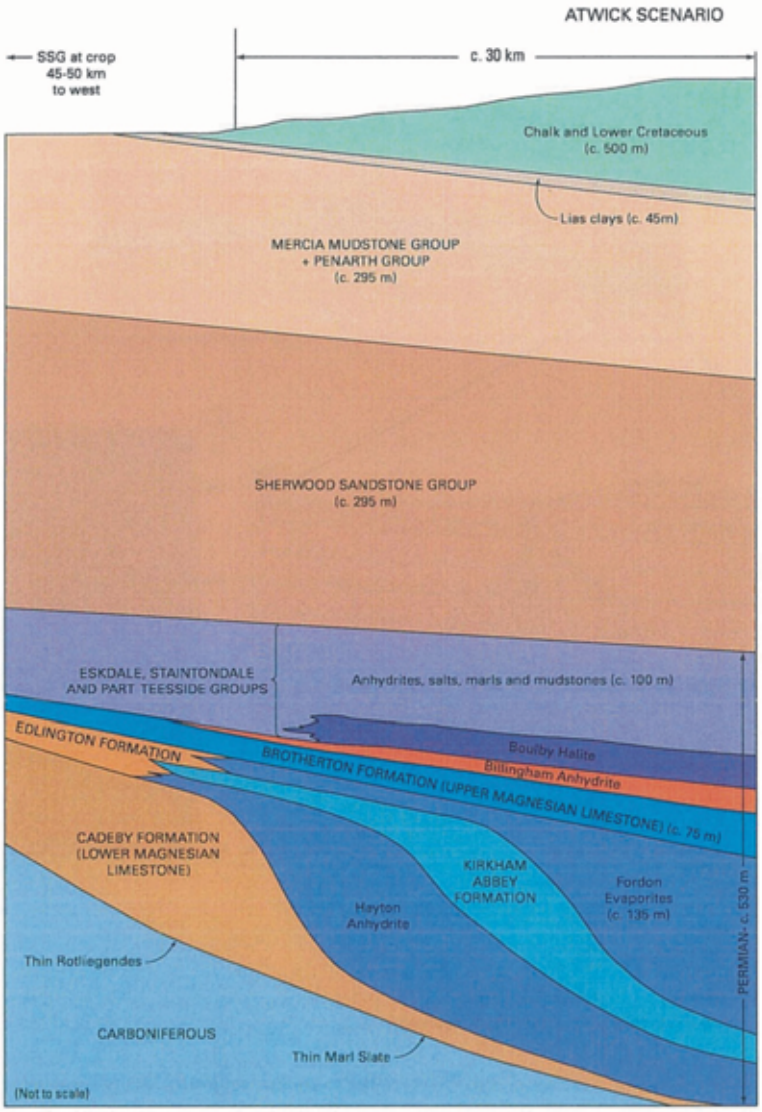
D2-253 (Cont.)



After Egdon Resources Ltd and Chadwick & Evans BGS©NERC. All rights reserved

Figure 57. General setting of the Dorset Halite in the region of the proposed salt cavern storage facility beneath the Weymouth-Isle of Portland area. a) Line illustration of the thickening of the (Dorset) halite of the Wessex Basin in the Weymouth Anticline, based upon depth converted seismic reflection data (Chadwick & Evans, 2005), b) sketch of the level of proposed gas storage caverns and layout (after Egdon, 2006a).

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(Cont.)



Depth top caverns	c. 1670 - 1900 m	Minimum pressure	c. 120 bar
Nos of caverns	9	Maximum pressure	c. 270 bar
Spacing	not known	Maximum cavern diameter	not known
Total volume	c. 420 Mcm	Cavern heights	c. 60 - <100m

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Figure 58. Sketch section illustrating the geological conditions likely to represent the 'NE England Permian scenario' (e.g. Hornsea/Atwick, Aldbrough).

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(Cont.)

Tables

Table 1 (following page). Summary of operational and planned underground gas storage facilities in Britain. Note: information regarding the caverns operational in the Teesside area and the product stored has been in part supplied by SABIC, whose assistance is gratefully acknowledged. This represents our most up to date information on the various caverns and stored products. However, more detail might become available with time.

[1] Note Table 2: DTI (2006a&b) figures, [2] Note Table 2: DTI (2006a&b) figure

D2-253
(Cont.)

Area	Site	Owner/operator	Storage capacity (bcm)	Number of caverns (Chalk & salt storage)	Approx. depth of storage (top-bottom if known - m)	Comments
Operational facilities – depleted oil and gasfields						
Rough (offshore)	Southern North Sea	Centrica	3,303	N/A	c. 2240	Operational since 1985
East Midlands	Hatfield Moors	Edinburgh Oil & Gas	122	N/A	c. 417	Operational since 2000
Wessex-Weald Basin	Humbly Grove	Star Energy	210	N/A	c. 982	Operational since 2005
Planned facilities – depleted oil and gasfields						
East Midlands	Welton	Star Energy	435	N/A	c. 1360	Planning application refused, likely Public Inquiry. Commission 2008?
East Midlands	Saltfleetby	Wingas UK Ltd	600	N/A	c. 2234	Planning application submitted January 2005. Commission 2009?
East Midlands	Hatfield West	Edinburgh Oil & Gas	Not known	N/A	c. 396	Planned - feasibility studies 2004-2005
East Midlands	Gainsborough	Star Energy	227-249	N/A	c. 1375	Pre-planning stage
East Yorkshire	Caythorpe	Warwick Energy Ltd	Up to 216	N/A	c. 1829	Planning consent refused 22 June 2006. Public Inquiry due to start 24 April 2007.
Wessex-Weald Basin	Albury – phase 1	Star Energy	160	N/A	c. 823	Pre-planning stage, commission 2007/08?
Wessex-Weald Basin	Albury – phase 1	Star Energy	Up to 715	N/A	490	Pre-planning stage, commission 2010?
Wessex-Weald Basin	Blechingley	Star Energy	Up to 569	N/A	c. 930-1143	Pre-planning stage, commission 2009?
Wessex-Weald Basin	Storrington	Star Energy	Not known	N/A	c. 1152	Pre-planning stage – application likely after feasibility studies.
Operational facilities – Chalk caverns						
North Lincolnshire	Killingholme	ConocoPhillips and Calor Gas	0.1 (liquid = 60,000 tonnes of LPG)	2	180-1210	Two mined caverns in Chalk c. 180 m below ground level, operational since 1985
Operational facilities – salt caverns						
Cheshire Basin	Holford H-165	InterGlobe (formerly operated by NG (Transco), now Inovyn)	0.175	1	350-420	Planning approval granted 1983. Ten year inspection completed 2006. One of number of abandoned brine cavities with ethylene & natural gas storage since 1984.
Cheshire Basin	Hole House Farm (Warmingham/Brinefield)	Energy Merchant (EDF Trading)	75	4	300-400	Planning approval granted 1995. 4 caverns, operations started in February 2001
East Yorkshire	Hornsea/Atwick	Scottish & Southern Energy	825	9	c. 1920-1825	Planning granted 1973, operating since 1979. 9 caverns planned.
Teesside	Saltholme	SABIC (formerly InterChlor/Huntsman)	Up to 0.12-0.2	18 (plus 9 redundant)	350-380	Development in 1970s, storage started 1985-1992. 18 ex ICI caverns in operation. 1 "dry" cavity storing nitrogen; 17 "wet" storage cavities containing hydrocarbons ranging from Hydrogen to Crude Oil; 9 redundant storage cavities, 75 redundant brine wells/cavities never used for storage; 5 in service brine wells.
Teesside	Saltholme	InterChlor/Northern Gas Networks	0.08	4	340-370	4 ex ICI natural gas cavities. Development started 1959-1963, storage started 1959-1983. Now owned by InterChlor & operated by Northern Gas Networks for natural gas.
Teesside	Wilton	SABIC (formerly InterChlor/Huntsman)	Up to 0.04	5 (plus 3 redundant)	650-680	Storage started from 1959 to 1983. 8 caverns leached, 5 operational cavities in total leached for storage purposes: 4 cavities storing Ethylene, 1 cavity storing Mixed Cit's. 3 cavities redundant or never in service for storage
Teesside	Wilton	Air Liquide/BOC	Not known	2	650-680	2 ex ICI cavities - operational & storing nitrogen (for BOC Nitrogen)
Planned facilities – salt caverns						
Cheshire Basin	Byley/Holford (southern end of Holford Brinefield - Drakelow Lane area)	Caverns operated by Scottish Power, sold to E.On UK plc	160-170	8	650-710	Secretary of State reversed Public Inquiry decision. Under construction, commission 2008? Salt caverns to be leased from Inovyn who own the salt & will construct caverns
Cheshire Basin	Byley/Holford (Holford Brinefield between Drakelow Lane and Lach Dennis)	Inovyn Enterprises Ltd	540[1]	28	550-560	Planning application December 2005, granted June 2006, fully consented August 2006. Government will not call in for Inquiry. Project progressing to design stage, commissioning 2009?
Cheshire Basin	King Street (Holford Brinefield)	King Street Energy (NPL Estates)	216	9	>400	Proposed construction of 9 cavities, each with a volume of 400,000 cubic metres, holding up to 216 Mcm of gas in total of which up to 126 Mcm will be working gas
East Yorkshire	Hornsea – Aldbrough N & S	Scottish & Southern Energy and Statoil	420	8	1800-1900	Planning granted 2000, 2 sites operational by Q3 2007?
NW England	Preesall	Cavendish Gas Storage Ltd	c. 1200[2]	20-24	345-510	Significant public objection to proposals. Public Inquiry held (October 05-May 06), Inspector's decision not expected before October 2007
East Yorkshire	North of Aldbrough	SOCH UK	420	Not known	c. 1800	Planning application submitted to East Riding of Yorkshire Council, January 2007. Subject to permission, work to start late 2007, first phase operational 2010, with completion 2013.
Wessex-Weald Basin, Dorset	Isle of Portland	Portland Gas Ltd. (subsidiary Egdon Resources)	300	14-18	2100-2300	Pre-planning stage, application due for discussion at County Council meeting March 2007.
Larne, N Ireland	Larne Lough	Portland Gas NI Ltd(subsidiary Egdon Resources)	Not known	Not known	1650	Feasibility study stage, scoping application in October 2007

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(Cont.)

Area	Type and Number of UGS facilities (2005)					Working Volume	Deliverability
	Gas & Oil Fields	*Aquifers*	*Salt Caverns*	*Other*	*Total*	*Bcm (10^9 m³)*	*Mcm*[*]*/d (10^3 m³/d)*
Europe	64	23	27	3	117	75	1,648
Former Soviet Union	36	13	1		50	110	983
U.S.A.	320	44	30		394	113.5	2,369
Canada	44		8		52	17	279
South America	2				2	0.2	2
Asia	7				7	2.6	14
Australia	5				5	1.0	10
Total (%age)	478 (76)	80 (13)	66 (11)	3 (<1)	627	319.3	5,105
Number of incidents in storage facilities	16	17	27	5			
Number of incidents in storage facilities as %age of number of facilities operational in 2005	3%	21%	41%	None operational, 2005			
Number of incidents in storage facilities involving casualties/ evacuations	3	2	9	5			
Number of incidents in storage facilities involving casualties as %age of number of facilities operational in 2005	0.63%	2.5%	13.6%	None operational, 2005			

UGS Figures for America 1997/2005				
	Number of facilities - 1997	*Working Volume (Bcm) - 1997*	*Number of facilities - 2005*	*Working Volume (Bcm) - 2005*
Gas & Oil Fields	346	94.3	320	97.3
Aquifers	41	9.97	44	11.3
Salt Caverns	27	3.3	30	4.9
Total	414	107.6	394	113.5

Consumption and storage volumes								
	Total gas consumption (Bcm) - 1997 (BP, 2006)	*Number of facilities - 1997*	*Working volume (Bcm) - 1997*	*%age gas storage/ consumption - 1997*	*Total gas consumption (Bcm) - 2005*	*Number of facilities - 2005*	*Working volume (Bcm) - 2005*	*%age gas storage/ consumption - 2005*
North America	769.3	414	107.6	14	775	446	130.5	16.8
Western Europe	341.3	75	53	15.5	427.4	117	c. 75	c. 17.6
Russian Federation	350.4	46	c. 80.5	c. 23	405	50	c. 110	c. 27.2
Total Europe and Russia-Eurasia	936.1	138	*Not available*	-	1121	174	*c. 187.3*	*16.7*
World Totals	**2249.7**	**580**	**262.4**	**11.7**	**2749.6**	**627**	**319.3**	**c. 11.6**

Table 2. Number of underground natural gas storage facilities, working volumes and deliverability, both worldwide and in the USA (based upon IGU, 2003; Favret, 2003; Plaat, 2004 & this volume; EIA, 2006).

[*] Mcm = million cubic metres (as used by DTI), equalling 10^6 m³

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(Cont.)

Table 3. Calculated diffusive fluxes for the McClave Field (Nelson & Simmons, 1995)

	Cap rock porosity	
	5%	*10%*
Methane loss (m^3/yr)	521	2383
Methane loss (mcf/yr)	18.4	84.1
Replacement time (m.y.)	2.21	0.485

Table 4. Calculated methane losses for a 1737 m and a 39.6 m thick caprock (Smith et al., 1971)

	Calculated losses for fields with hypothetical gas production			
	1737 m thick caprock		**39.6 m thick caprock**	
	283.2 Mcm (10 bcf)	*2.83 Bcm (100 bcf)*	*283.2 Mcm (10 bcf)*	*2.83 Bcm (100 bcf)*
Methane loss (m^3/yr)	2,832 (0.0028 Mcm)	21,294 (0.0213 Mcm)	124,310 (0.124 Mcm)	934,455 (0.935 Mcm)
Methane loss (mcf/yr)	0.100	0.752	4.39	33.0

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Table 5. Summary of the main hydrocarbon province characteristics and significant discoveries onshore UK.

Province	Typical hydro-carbon occurrence	Typical Reservoirs	Source(s)	Trap type	Examples
Wessex-Channel Basin (including the Weald Basin)	Oil and gas	Bridport Sands, Great Oolite (Jurassic), Sherwood Sandstone Group (Triassic)	Lower Lias (clays Jurassic)	Tilted fault blocks & Palaeogene inversion anticlines	Oil: Wytch Farm, Kimmeridge, Humbly Grove, Stockbridge, Wareham Gas: Albury
East Midlands	Oil and gas	Silesian sandstones & fractured Dinantian limestones (Carboniferous)	Silesian (Carboniferous) mudstones and coals	Variscan anticlines and stratigraphic traps	Oil: Eakring, Welton, Rempstone, Scampton, Gainsborough Gas: Hatfield Moors and Hatfield West, Trumfleet, Saltfleetby
Yorkshire/NE England	Gas	Permian limestones (e.g.Upper Magnesian Limestones)	Silesian (Carboniferous) mudstones and coal	Mesozoic folds	Malton, Marishes, Lockton, Eskdale
NW England	Oil and gas	Sherwood Sandstone Group (Triassic)	Silesian (Carboniferous) mudstones and coals	Variscan anticlines, stratigraphic – superficial deposits trapping oil	Oil: Formby Gas: Elswick
Midland Valley Scotland	Oil and gas	Silesian sandstones (Carboniferous)	Silesian (Carboniferous) mudstones and coals	Variscan (end Carboniferous-Permian) anticlines	Oil: Dalkeith, Gas: Cousland

Table 6. Tolerance of microbes to extreme environments (West & McKinley, 2001).

Condition	Example of organism	Limit of growth
High temperature	'Black smoker' bacteria	Reported to 113^{0}C.
Low temperature	*Sporotrichum carnis*	-20^{0}C
High pH	Nitrifying bacteria	12
Low pH	*Thiobacillus ferrooxidans*	0
High salinity	*Halobacterium halobium*	50% salt by weight
Low salinity	*Salmonella oranienburg*	70ppb dissolved salts
High pressure	*Desulfovibrio desulfuricans*	180MPa
Radiation	*Deinococcus radiodurans*	Single dose 5000 Gy
Chemical toxins e.g. $PbCl_2$	*Aspergillus niger*	67 mg ml^{-1}

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		Storage Type				
		Depleted oil/gas fields	Aquifer	Salt Cavern	Abandoned mine	Total
Main processes attributed to leak/failure mechanism/abandonment of facility	well/casing problem/failure	3	6	11		20
	above ground infrastructure - valve/pipe/wellhead/compressor	3	1	7		11
	failed pressure test – facility never commissioned			1		1
	design/construction failure – facility never commissioned			3		3
	inadvertent intrusion	1	1			2
	drilling repair/testing/maintenance	2	2	1		5
	Overpressure equip/overfilling event		1	2		3
	migration from injection facilities	5				5
	cap rock – out gas tight		9		2	11
	cap rock - fractured	2	4			6
	salt creep			3		3
	cavern communication			1		1
	mine shaft				1	1
	wet sinkhead/sinkholes			1	1	2
	seismic activity	1				1
	gas shallow, facility abandoned		1			1
	loss of wellhead pressure			1		1
	not determined	1		2		3
	Unspecified product			2		2
	Natural gas/town gas	16	17	8	2 (coalmine)	43
	Propane/LPG			8	1 (coalmine?), 1 'unlined cavern'	10
	Ethane			1		1
	Ethylene			3		3
	Butane			1		1
	Crude oil			1	1 (saltmine)	2
Incidents by country/US state	California	11	1			12
	Illinois	1	8		1 (coalmine?)	10
	Texas			10		10
	Louisiana	1		5	1 (saltmine)	7
	Kansas			2		2
	Mississippi			3		3
	Rest of America (including Canada)	1	3	3	1 (coalmine?), 1 'unlined cavern'	9
	France		1	2		3
	Germany	1	3	2		6
	Belgium				1 (coalmine)	1
	Denmark		1			1
	UK	1				1
Fire/explosion associated with the incidents		4	1	10		15
Total number of incidents		16	17	27	5	65
Number of incidents involving arson/malevolence (% age of incidents)		1 (=10%)	2 (=12%)	9 (=33%)	None operational, 2005	
Total number of facilities as % age of facility numbers in 2005 (facility numbers – Table 1)		=0% (478)	=21% (80)	41% (66)	None operational, 2005	
Human impact	Dead - America			8		9
	- Rest of World		1			
	Injured - America	3		48		c. 62
	- Rest of World	2	9			
	Evacuated - America	c. 52		6110		c. 6708
	- Rest of World	31	700			
	Total dead	0	1	8	0	9
	Total injured	5	9	48	0	c. 62
	Total evacuated (excluding village of Knoblauch, Germany – numbers not found)	83	>100	c. 6110	0	c. >6709

Table 7. Summary of main processes leading to leakage from and failure of underground hydrocarbon storage facilities.

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(Cont.)

Depleted Oil/Gasfield Storage						
Facility	**Operator**	**Product**	**Date**	**Description of event/fatalities/injuries**	**Reported cause/comment**	**Main reference(s)**
Incidents involving casualties/large evacuations						
Fort Morgan, Colorado, USA	Colorado Interstate Gas Co.	Gas	October 2006	Gas leak, halting storage operations. 13 families evacuated (p. 52)	Well leak – completion failed	State of Colorado (2006); (http://costa.sin.dos.gov/oogcf/safety/setupdate.asp).
Rough Field, Southern North Sea, UK sector	Centrica	Gas	Feb 2006	Explosion and fire, 2 injured, 31 airlifted from platform	Catastrophic failure of a cooler unit in one of the four glycol dehydration units, leading to explosion in vicinity	Centrica (2006)
Southern Illinois, USA	Not available	Gas	Feb 7th 1997	Explosion & fire. 3 employees injured	Inadvertent strike of gas from UGS reservoir during drilling of oil well	Hadlaw (2002)
Casualty Totals				*5 injured/c. 82 evacuated*		
Incidents where no casualties involved but financial or property loss or closure occurred						
Breitbrunn/Eggstatt Gasfield in Bavaria, Germany	Not available	Gas	2003	Pressure increase in the first months of borehole	Failure of the well completion	Bary et al., (2002) ; Oberer et al., 2004
Playa del Rey, LA, California, USA	SoCal	Gas	April 2003	25 minute release of gas with a fine mist of oil	Valve in compressor unit broke	Peterson & Marquez (2003)
Castac Hills & House Ranche, Calif., USA	SoCal	Gas	1975-present?	Gas migrating from Castaic reservoir to adjacent fields & chance to surface	Gas migrates to shallower House Ranche & Tapia reservoirs, via faults to surface killing oak trees	Davis & Marsden (2004); Khilyuk et al., 2000)
Montebello, LA California, USA	SoCal	Gas	1950s-1980s	Storage gas lost over extended period	Storage gas migrated from injection area. Injection ceased 1986, facility closed 2002	Benson & Hepple (2005); Chilingar & Endres (2005); EIA (2006)
Playa del Rey, LA, California, USA	SoCal	Gas	1940s-present day	Migration of stored gas	Stored gas has been migrating from Playa del Rey structure into Venice structure from earliest days, some fault related	Reigle (1953); Exploration Technologies Inc., (2000); SoCal, (2004); Chilingar & Endres (2005)
McDonald Island, Stockton, California, USA	Pacific Gas & Electric Co.	Gas	Oct 1993	Explosion, causing US $2 million damage	Explosion in moisture extraction (gas conditioning) plant	Lee (1998); Delta Protection Commission (1997)
Epps, Louisiana, USA	Tremdina	Gas	1960s-1990s	Injected gas produced elsewhere in structure – first gas reservoir	Gas migrated away from injection footprint – connection between traps. Facility remains operational	Coleman (1992); EIA (2006)
McDonald Island, Stockton, California, USA	Pacific Gas & Electric Co.	Gas	1974	Explosion, fire burned for 15 days, 0.42 bcm gas consumed	Not available	San Joaquin County (1992)
East Whittier, California, USA	SoCal	Gas	1970s	Gas migrated from original injection site	Injected gas produced by other company, facility eventually closed in 2002.	Benson & Hepple (2005); EIA (2006)
El Segundo, California	Not available	Gas	Early 1970s	Gas migration - facility abandoned due to new housing	Gas migration from reservoir to surface. Abandoned for safety.	Khilyuk et.al. (2000)
California, USA	Not available	Gas	Not available	Storage well damaged - crushed	Storage well damaged during earthquake	Vector Magnetics (http://www.vectormagnetics.com/casehistories.pdf)
California, USA	Not available	Gas	Not available	Storage well damaged - casing shoe leak	Well inadvertently sidetracked during repair of casing shoe leak	Vector Magnetics (http://www.vectormagnetics.com/casehistories.pdf)
California, USA	Not available	Gas	Not available	Corrosion of storage well casing	Well inadvertently sidetracked during repair of corroded casing	Vector Magnetics (http://www.vectormagnetics.com/casehistories.pdf)

Table 8. Summary of documented incidents or problems reported at underground hydrocarbon storage facilities developed in depleting oil/gasfields, some of which have led to leakage and/or failure.

Aquifer Storage						
Facility	**Operator**	**Product**	**Date**	**Description of event/fatalities/ injuries**	**Reported cause/comment**	**Main reference(s)**
Incidents involving casualties/large evacuations						
Spandau, Germany	GASAG	Gas	April 2004	Explosion, 9 injured, 3 seriously, 500 evacuated in 1 km radius of incident	Explosion, perhaps linked to maintenance work, a defective seal, or work on the facilities contents gauges, destroyed the wellhead	Associated Press (April 23rd, 2004); F May (pers com (2004)
Ketzin (Knoblauch), Berlin, Germany	1960s not available, latterly UGS Bildenwalde	Town gas (1960s), natural gas (1970s-2000)	1960s-2000	1960s-gas migration from reservoir to surface, town of Knoblauch evacuated (permanently?), 1 fatality in large	Caprock not gas tight – migration along faults in cap rock also thought likely. The 1 fatality linked to CO migrating up old well into house	http://www.mydeltaquest.com/english/archive-New-technology-would-store-carbon-underground; Juhlin et al. (2007); NJ Riley (pers com., 2007)
Casualty Totals				*1 dead, 9 injured, >500 evacuated*		
Incidents where no casualties involved but financial or property loss or closure occurred						
Stenlille, Denmark	Danish Oil and Gas Company (DONG)	Gas	1995	Gas in shallow aquifer and bubbled to surface	Casing leak	Lalot & Ebert (2004 & in press)
Chémery, France	Gaz de France	Gas	Sept 1989	Major gas leak, no explosion. Flights diverted around gas cloud	During routine maintenance of well completion and replacement of a filter	NAWFC (1999); IAVWOPSG (2005);
Frankenthal, Germany	Saar-Ferngas	Gas	Sept 1986	Gas escape, no explosion, no casualties	Drilling into existing pipework?	AEA (2005)
Lenroy, Wyoming, USA	Mountain Fuel Supply Co.	Gas	1973-mid 1980s	Numerous incidents of gas escaping	Corroded well casing & overpressuring of aquifer	Katz and Tek (1981); Anderson et al. (1984); Nelson et al. (2005)
Pleasant Creek, California, USA	Not available	Gas	1972-1976	Soil gas surveys detect gas over storage area	Gas migrating up out of reservoir. Poor seal?	Jones & Drozd, 1983; Jones & Pirkle; http://www.all-geochemistry.com/FinalVersion1.10.html
Sciota, Illinois, USA	Central Illinois Public Service Company	Gas	1971-1976	Testing and injection 1971-1972	Ineffective seal provided by caprock, facility was abandoned in 1974	Buschbach & Bond (1974); Coleman et al. (1977)
Pontiac, Illinois, USA	Northern Illinois Gas Company	Gas	1963-1974	Testing and injection with inert combustion gas 1970	Ineffective seal provided by caprock, facility was inactive in 1974	Buschbach & Bond (1974); Coleman et al. (1977)
Leaf River, Illinois, USA	Northern Illinois Gas Company	Gas	1968-1977	Water pump and injection tests several leak	Faulting, caprock leak, facility abandoned	Buschbach & Bond (1974); Coleman et al. (1977)
Chalk Creek & Coalville, Utah, US	Questar, still operational	Gas	1970s	Soil gas surveys detect gas over storage areas	Gas migrating up out of reservoirs – faults?	Jones & Drozd, 1983; Morgan (2004)
Brookville, Illinois, USA	Natural Gas Pipeline Company	Gas	1963-1966	Water pump and injection tests indicated leak from reservoir	Faulting, caprock leak, facility abandoned	Buschbach & Bond (1974); Coleman et al. (1977)
Manlove, Illinois, USA	Peoples Gas Light and Coke Company	Gas	1961-1963	Gas migrated from 2 upper reservoirs into glacial drift deposits	Reservoirs abandoned but 3rd, deeper one later developed	Buschbach & Bond (1974); Coleman et al. (1977)
Waverley, Illinois, USA	Panhandle Eastern Pipeline Company	Gas	1960s	Gas migration to shallower levels	Gas was either recycled into reservoir, or produced	Buschbach & Bond (1974); Coleman et al. (1977)
Troy Grove, Illinois, USA	(The then) Northern Illinois Gas Company	Gas	1957-1959	Gas migration from reservoir known since early development	Gas withdrawn from higher levels and re-injected at depth. Facility still operational	Buschbach & Bond (1974); Coleman et al. (1977); Hitni (2004)
Hudson, Illinois, USA	Natural Gas Storage Company of Illinois	Gas	April-July 1953	Gas found in shallow water wells within 6 weeks of operation	Injection stated, blind wells drilled - withdrew water from periphery & injected into overlying formations preserve	Buschbach & Bond (1974); Coleman et al. (1977)
Northern Indiana, USA	Not available	Gas	Not available	Gas escape	Reservoir selected too shallow, number of water wells were affected by the intrusion of natural gas. Facility abandoned	Buschbach & Bond (1974); Perry (1995, 2007 pers comm.)

Table 9. Summary of documented incidents or problems reported at underground hydrocarbon storage facilities developed in aquifers, some of which have led to leakage and/or failure.

Table 10 (next page). Summary of documented incidents or problems reported at underground hydrocarbon storage facilities developed in salt caverns, some of which have led to leakage and/or failure.

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Salt Cavern Storage						
Facility	Operator	Product	Date	Description of event/failure/release	Reported cause/summary	Main reference(s)
Facilities involving considerable gas movement						
Moss Bluff, Texas, USA	Duke Energy	Gas	August 19th - 25th 2004	Fire & explosion, circa 360 evacuated, circa 100.9 Mscf (Mscf) of natural gas released and burned. Fire allowed to self-extinguish by turning off the remaining gas	[illegible] expansion and breach of the 8 3/4-inch well string inside the cavern, pinhole leak in well string of the 'water transfer' tubing, breach of corroded pipe above ground, escaping gas ignited, resultant fire caused wellhead to fall with blowout preventer successfully installed on 26th August.	Duke Energy (2004); [http://www.solutionmining.org/user/FileFiles/Moss%20Bluff_Fact%20Sheet_8_Incident%20Story.pdf]
Maynard, Napoleonville, Louisiana, USA	Energy-Koch (Gulf South)	Gas	Dec 24th 2002	One fatality/evacuation. c. 9.9 Mscf gas released in five hours. 10 evacuated	Casing failure; crack in the casing of a well near the top of a cavern	Hopper (2004); [http://www.rigzone.com/news/article.asp?a_id=1994&print=yes]
Conway, McPherson County, Kansas, USA.	Williams Midstream Natural Gas Liquids	Propane	1999b-2002	NGL's found in wells & local groundwater. 10 homes bought and c. 100 people relocated (#40-61).	Problems possibly related to effects of two wells/pool	Raiga-et al. (2002)
Hutchinson/Yaggy, Kansas, USA	Crawl	Gas	January 2001	Fire & explosion, 2 dead, 8 injured & 2000 people evacuated	Casing failure – corroded during cavern operations. $3.25 million punitive damages. Problem with reduced tool string another minor incident, which was later corrected into storage.	AS Inc (2001-info), Kansas Geological Survey (2001) and [illegible]
Brenham, Texas, USA	Mason	LPG (propane, butane, ethane)	April 1992	Fire & explosion, 3 dead, 22 injured, 30 evacuated, 20 homes destroyed, within 1.5 miles of the explosion, damage to further 30 homes	Overfilling and valve failure. $5.4 million & $1.38 million punitive damages awarded	NTSB (1993-info, 2002); Thoms & Gehle (2000); Bérest & Brouard (2003)
Mont Belvieu, Barbers' Hill, Texas, USA	Not available	Propane	Nov 5th 1985	Fire & explosion, 2 dead, 3000 evacuated	Casing failure	Bérest et al. (2001)
Mont Belvieu, Barbers' Hill, Texas, USA	Not available	Propane	Sept 17th 1992	Fire & explosion, 75 families evacuated (c. 300)	Casing failure - corrosion	Bérest et al. (2001)
West Hackberry, Louisiana, USA	SPR	Oil	Sept 1978	Fire, 1 dead, c. 72,000 bbls crude oil released	Failure/failure during repair of casing	DOE (1980); Bérest & Brouard (2003)
Petal, Mississippi, USA	Not available	Butane	August 1974	Fire & explosion, 24 injured, 3000 evacuated	Overfilling of cavern	USA (1985); Wendling et al. (1988); ASA (1969)
Citronelle, Texas				8 dead/68 injured, 4,124 evacuated		
Incidents where gas movement involved but did not or presently less or elements escaped						
Odessa, Texas, USA	Ukrainian Petroleum	Propane/butane	18 March 2004	110 (c. 114.5 m³) natural gas liquids stored at 600 psi escaped from wellhead/pipe and storage system, between 8.31 psi and midnight. Ethylene being added to storage at time	Metal gasket in a wellhead flange failed, remaining gas flared off, no reported injuries	Hazardous Cargo Bulletin (June 2004); in Kirkpatrick.com, 2007); [http://www.accessmylibrary.com/coms2/summary_0286-17025465_ITM]
Fort Saskatchewan, Alberta, Canada	IP Canada	Ethane	August 2001	One leak & fire. Established that 14,300 m³ of ethane was lost over 8 days	Valve failure	CUB (2002)
Mont Belvieu, Texas, USA	Valvulina Pegasus	Propane	1995 (1997?)	Casing leak, blew out & fire	Cavern operations led to connection between adjacent caverns, sudden pressure build-up and casing leak	Calderoni et al. (1999); Bérest & Brouard (2003); Warren (2006); [http://www.worldoil.com/Forbidden.gif?uri=/data/]
Starrco Ridge, Texas, USA	MG/Dow	Gas	1990s	Cavern failure	Leak – failed MIT	Pepper (1996)
Clute, Texas, USA	Dow Chemical Co. & 5 Texas Pipeline Companies	Ethylene	1968/1969	24 million m³ ethylene (7 million gallons) lost between December 1968 & March 1969. Escaped at 396 m depth. Collected beneath caprock to salt dome	Product escaped from casing leading to the cavern & related to movement in the salt dome? Relief well drilled and product burned off.	Kolmetz (2007); [http://kolmetz.com/pdf/Maplefarm-safety-lessons.pdf]
Virgil, France	Site available	Ethylene	1986	Gas cloud	Rupture of impervious unit	Bérest-Kirby (1988, 2002, pers.com)
Mont Belvieu, Texas, USA	Not available	Propane	October 1984	Fire & explosion, several million $'s damage	Casing failure	Bérest et al. (2001)
Teutschental, Germany	Not available	Ethylene	March 1983	ethylene leak & explosion	Leak in the ethylene	Rüttling et al. (1983); Kansas Geological Survey website [http://www.kgs.ku.edu/Hydro/publications/OpenFile/2003/ofr03_3a.html]
Jefferson, Mississippi, USA	Not available	Natural gas/salt cavern	Early 1980's	Natural gas leakages, no reports of casualties	4 caverns in facility, wells #2 found to be leaking due to poor cementing	Pfeifle (1984); Pfeifle & Jones (2004)
Elk City, Oklahoma, USA	Not available	Unspecified	Early 1970s	Surface depression, boulders thrown in air	Unspecified	Kaye (1974)
Eminence, Mississippi, USA	Texaco	Gas	April 1972	Lost capacity. Closed in the early 1980s, but volume had been reported small. Gas/brine leakage	Salt creep – too low operating pressure range.	Allen (1972); Bier (1977); Bérest & Brouard (2003); Wallace (2004)
Bryan Mound, Texas, USA	Not available	Unspecified gas	1980s	Loss of wellhead pressure	Cavern abandoned empty, 30 years later still solid.	Weaver (2004)
Goodyear Anticline, USA	Not available	Propane	Not available (Infrastructure)	Several million cubic feet of propane lost	Corrosion fatigue in well casing at depth around 91 m below ground	Pfeifle (1984); Pfeifle & Jones (2004)
Kiel, Germany	AG	Town gas + hydrogen (60% - 1970)	1960s-present?	Lost capacity, caverns operated from 1958 to at least 2001. Town gas change over 1970's	Salt creep	Crotogino et al. (1981); Pudel & Palmtag (1999); Bérest & Brouard (2003)
Tersanne, France	Gaz de France	Natural gas	1970-2019	Lost capacity, caverns still operational, leaking regional mass of marine related brine	Salt creep	Bérest & Brouard (2003); Warren (2006)
Bayou Choctaw, Baton Rouge, Louisiana, USA	Not available	Empty caverns	1954	Collapse of overburden into the developing cavern number 7	Uncontrolled leaching operations	Coates et al. (1968); Neal & Magorian (1997)
Chacahoula, Louisiana, USA	Not available	Empty caverns	Not available	Insufficient thickness of salt to act as a barrier	Cavern leaching at the salt overhang	Neal & Magorian (1997)
Napoleonville, Louisiana, USA	Not available	Empty caverns	Not available	Thin layers of salt above side encountered in some caverns, leaving insufficient healthy salt	Salt dome edge and overlying cavity had been encountered	Neal & Magorian (1997)

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Abandoned Mine Storage						
Facility	Operator	Product/type	Date	Description of event/fatalities/injuries	Reported cause/comment	Main reference(s)
Weeks Island, Louisiana, USA	US Dept. of Energy	Oil/salt mine	1981-1994	Loss of salt mine cavern integrity at SPR facility	Sinkholes caused by leaching of salt and collapse of mined caverns	Neal & Magorian (1997); Warren (2006)
Anderlues, Belgium	Not available	Gas/coal mine	1980-2000	Leakage from coal mine. Operations ceased in 2000 due to connectivity with shallower mine levels such that gas escaped to overlying strata, very costly maintenance work on shafts and the high adsorption levels of the gas onto the coal seams	Caprock not gas tight, gas leaked out of mine workings	Piessens & Dusar (2003)
Leyden, Arvada, Colorado, USA	PSCo	Gas/coal mine	1960s-2000	Leakage from coal mine. $278,000 damages, facility closed 2001.	Caprock not gas tight, gas leaks out of mine workings	Raven Ridge Resources (1998)
Crossville, Illinois, USA	Not available	Propane/coal mine	mid 1960s - 2000	Leakage from mine. No reported casualties	Leakage from the shaft, once in overburden migration was pressure driven along faults, fractures and joints	Pirkle (1986); Pirkle & Price (1986); Jones & Burtell (1994)
Unlined rock cavern (salt?)						
Ravenswood, Virginia, USA	Washington Gas Light Company	Propane/ unlined rock cavern	24 Aug. 1973	Smell of gas reported, with gas bubbling up 300m from a residential area. Water injected around well to stem migration of gas in subsurface.	Not clear, but apparent propane escaped from an underground unlined rock cavern	Reeser (1989); N Riley, HSE pers com 2007

Table 11. Summary of documented incidents or problems reported at underground hydrocarbon storage facilities developed in abandoned mines, some of which have led to leakage and/or failure

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(Cont.)



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Table 12. Details of operating European UGS sites in MARCOGAZ survey of European UGS incidents to 2000 (from Joffre & LePrince, 2002).

Countries	Number of UGS sites	Number of active storage wells	Number of cumulated years of site operation	Average number of years of cumulative well operation
Austria	4	25	178	2225
Belgium	2	10	40	200
Denmark	2	25	20	250
France	13	355	294	52185
Germany	10	114	213	12247
Italy	9	307	215	33002
Spain	2	9	10	45
Totals	**42**	**845**	**970**	**100155**

Table 13. Breakdown of the information collected during the MARCOGAZ survey of European UGS incidents to 2000 (from Joffre & LePrince, 2002).

Substances involved	
Criteria	*Number of events*
Natural Gas	7
Oil	3
Solids	1
Total:	*11*
Immediate source of accident	
Criteria	*Number of events*
Storage (wells)	5
Surface process (compressor, treatment, piping)	6
Suspected Cause	
Criteria	*Number of events*
Human	3
Plant/equipment	8
Immediate Effects	
Criteria	*Number of events*
Injuries	2 (1 light) (1 severe + 2 light)
Material + release of gas	6
Not available	3
Emergency Measures Taken	
Criteria	*Number of events*
Well closed	1
Emergency plans activated	2
Checking process	1
None	1
Not available	6
Immediate Lessons Learnt	
Criteria	*Number of events*
Redundant blowout preventor installed	2
New design of installation	5
None	3 (unique accidents)
Not available	1

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(Cont.)

Table 14. Summary of main casualty figures from various oil, gas and petrochemical incidents in the USA and rest of the world. Figures relating to Office Pipeline Safety (OPS) and HSE for domestic gas supplies partly duplicate those pipeline figures in the USA summarised in Tables 15 & 16, which were the major incidents covered in NTSB reports.

Type of Incident/Industry		Numbers reported dead	Numbers reported injured	Numbers reported evacuated
UFS[2]	USA – Tables 7-11	8	48	6,110
	Rest of world – Tables 7-11	1	14	c. 583 (excluding Ketzin)
Energy Supply Chain	Above ground storage tanks (world - 1951-2003; Persson & Lönnermark, 2004; Clark et al., 2001) – Table 20	778	426	>7,000
	Oil sector – (1986-2005; Hirschberg et al., 1998; Table 17)	15,695	20,276	274,746
	Gas sector (1986-2005; Hirschberg et al., 1998; Table 17)	2,233	5,210	105,011
	LPG sector (1986-2005; Hirschberg et al., 1998; Table 17)	3,701	21,120	961,776
	Railroad (USA) – Table 19 (NTSB reports; http://www.ntsb.gov/Publictn/R_Acc.htm)	9	5,441	10,452
	Petrochemical plants – world (Table 18; HSE, 1975; KAMEDO, 2000; Doyle, 2002; Marsh, 2003; Gruhn, 2003 & Macalister, 2005)	3,674	303,342	7,200
	OPS (USA) 1986-2006(part) - Transmission & distribution network & hazardous liquid pipelines (Table 15)	449	1,978	Not available
	HSE (UK) 1986-2005 domestic gas supply/use – Table 16 (figures in brackets = number from CO poisoning)	729 (576)	4,273 (3,346)	Not available

[2] UFS has been ongoing in the Canada and the USA since 1915 and 1916 respectively and in Europe since the 1950s (see section 2.2.4.2 of the main report). For storage utilising depleting oil/gasfields, incidents involving casualties have only been found reported since 1997, although migrating gas has been known in some Californian gas storage facilities since the 1940s. Although leakage has been known in some aquifer storage facilities since the early 1950s, the few casualties are reported, with 1 fatality in the 1960s and 9 injured in 2004. For salt cavern storage facilities problems and leakages have been reported since the early-mid 1950s, although casualties associated with this storage type have been found reported from 1974.

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Table 15. American OPS statistics for reported incidents and casualties involving both hazardous liquids and gas supply for the period 1986-2006(part) – refer http://ops.dot.gov/stats/stats.htm).

Year		Hazardous Liquid Pipeline Operators			Gas Distribution Operators			Gas Transmission Operators	
	No. of Accidents	*Fatalities*	*Injuries*	*No. of Incidents*	*Fatalities*	*Injuries*	*No. of Incidents*	*Fatalities*	*Injuries*
1986	210	4	32	142	29	104	83	6	20
1987	237	3	20	163	11	115	70	0	15
1988	193	2	19	201	23	114	89	2	11
1989	163	3	38	177	20	91	103	22	28
1990	180	3	7	109	6	52	89	0	17
1991	216	0	9	162	14	77	71	0	12
1992	212	5	38	105	7	65	74	3	15
1993	229	0	10	121	16	84	95	1	17
1994	245	1	7	141	21	91	81	0	22
1995	188	3	11	97	16	43	64	2	10
1996	194	5	13	110	47	109	77	1	5
1997	171	0	5	102	9	67	73	1	5
1998	153	2	6	137	18	64	99	1	11
1999	167	4	20	118	16	80	54	2	8
2000	146	1	4	154	22	59	80	15	18
2001	130	0	10	124	5	46	87	2	5
2002	147	1	0	102	10	44	82	1	5
2003	131	0	5	141	11	58	97	1	8
2004	144	5	16	175	18	41	123	0	3
2005	137	2	2	170	14	38	182	0	7
2006 (part)	86	0	0	102	11	19	107	1	3
Totals	3,679	44	272	2,851	344	1461	1,880	61	245
Total no. incidents	8,410								
Total no. fatalities	449								
Total no. injuries	1,978								

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Table 16. UK gas safety statistics illustrating known incidents relating to supply and use of flammable gas for the period 1986-2005 and which resulted in fatalities/injuries (based upon published Health & Safety Executive figures). The cause of incidents resulting in death or injury and which were not known (or related to suicide) are not included here. Note: the HSE fatalities refer to the gas distribution system and use of gas and not the transmission system.

	1986/ 1987	1987/ 1988	1988/ 1989	1989/ 1990	1990/ 1991	1991/ 1992	1992/ 1993	1993/ 1994	1994/ 1995	1995/ 1996
Total number of incidents (resulting in fatalities/ injuries)	131 (60/71)	148 (71/77)	126 (45/81)	130 (68/62)	121 (43/78)	139 (50/89)	138 (35/103)	179 (47/132)	146 (35/111)	146 (42/104)
Explosion/fire (number of fatalities/ injuries)	12/58	12/72	6/42	15/67	11/48	8/63	3/39	9/52	4/35	6/51
CO poisoning (number of fatalities/ injuries)	35/85	48/76	41/94	34/83	30/131	33/184	41/176	29/252	30/198	29/141
Totals (fatalities/ injuries)	*47/143*	*60/148*	*47/136*	*49/155*	*41/179*	*41/247*	*44/215*	*38/304*	*34/233*	*35/192*
(Based upon HSE figures – HSE, 2005, 2006)										

	1996/ 1997	1997/ 1998	1998/ 1999	1999/ 2000	2000/ 2001	2001/ 2002	2002/ 2003	2003/ 2004	2004/ 2005	2005/ 2006 (part	Sub totals
Total number of incidents (resulting in fatalities/ injuries)	143 (40/103)	164 (45/119)	151 (37/114)	174 (56/118)	174 (38/136)	154 (44/110)	114 (33/81)	127 (34/93)	147 (37/110)	151 (31/120)	2903 891/2012
Explosion/fire (number of fatalities/ injuries)	9/33	8/43	11/30	10/61	8/36	5/47	5/38	5/43	2/42	4/25	153/927
CO poisoning (number of fatalities/ injuries)	31/156	27/189	33/194	23/225	25/265	23/169	20/138	11/171	18/203	16/228	576/3346
Totals (fatalities/ injuries)	*40/191*	*35/252*	*44/224*	*33/286*	*33/301*	*27/216*	*25/176*	*16/214*	*20/255*	*20/253*	*729/4273*

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(Cont.)

Table 17. Summary of casualty figures for varying stages of the energy chain. Based largely upon the ENSAD (severe accidents) database for oil, gas and LPG production and supply for the period 1969-1996 (from Hirschberg et al., 1998).

Category		Casualty Figures - sector			
		Oil	*Gas*	*LPG*	*Totals*
Not known	Fatalities	813	22	88	*923*
	Injured	1,224	445	147	*1,816*
	Evacuees	22,000	15,710	303,900	*341,610*
Exploration/extraction	Fatalities	1,502	158	5	*1,665*
	Injured	4,453	61		*4,514*
	Evacuees	1,000			*1,000*
Transport to refinery	Fatalities	5,839			*5,839*
	Injured	883			*883*
	Evacuees	20,240			*20,240*
Long distance transport	Fatalities		987	828	*1,815*
	Injured		1,857	1,578	*3,435*
	Evacuees		82,525	3,501	*86,026*
Refinery/processing	Fatalities	399	8	164	*571*
	Injured	1,966	345	393	*2,704*
	Evacuees	23,430		161,000	*184,430*
Regional distribution	Fatalities	7,142	226	1,988	*9,356*
	Injured	11,750	936	11,523	*24,209*
	Evacuees	208,076	300	477,365	*685,741*
Local distribution	Fatalities		600	330	*930*
	Injured		1,349	7,199	*8,548*
	Evacuees		4,476	1,900	*6,376*
Heating/industrial	Fatalities		232	298	*530*
	Injured		217	280	*497*
	Evacuees		2,000	14,110	*16,110*
Totals	***Fatalities***	***15,695***	***2,233***	***3,701***	***21,629***
	Injured	***20,276***	***5,210***	***21,120***	***46,606***
	Evacuees	***274,746***	***105,011***	***961,776***	***1,341,533***

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(Cont.)

Table 18 . Significant petrochemical plant accidents involving death or injury.

Petro-chemical industry incidents						
Location	**Information source**	**Operator**	**Type**	**Date**	**Description of event/fatalities injuries**	**Reported cause**
Coliseum, Indianapolis	KAMEDO (2000)	Not available	Gas	1963	Explosion, 66 dead, 436 injured	Functional fault at refrigeration plant, gas release and explosion
Flixborough, N Lincolnshire, England	HSE (1975), Marsh (2003)	Nypro (UK)	Cyclo-hexane	1st June 1974	Explosion and fire, 28 dead, 104 injured, 3000 evacuated	Bypass pipe failed during a pressure surge, releasing product which formed a cloud that exploded (unconfined vapour cloud explosion)
Bhopal, India		Union carbide	Chemical plant - Methyl isocyanate	3rd Dec 1984	Major leak, 3500 dead, over 300000 injured	Major leak from holding tank with stored MIC overheated and released toxic heavier-than-air MIC gas, which rolled along the ground through the surrounding streets. The gas may ultimately have injured between 150,000 to 600,000 people, at least 15,000 of whom later died
Pasedena, Texas		Phillips	Chemical	23rd Oct 1989	Explosion and fire, 23 dead, 130 injured	Release of highly flammable process gases during regular maintenance operation. Vapour cloud ignited.
Deer Park, Texas		Arco Chemical Co		1990	17 dead	Not available
Belpre, Ohio	Doyle (2002)	Shell	Chemical storage	27th May 1994	Fire and explosion, 4 dead, 1700 evacuated	Fire at chemical plant spreads to nearby storage tanks, with loss of millions of gallons of chemicals
Port Neal, Iowa	Marsh (2003), Gruhn (2003)	Terra industries	Chemical plant	13th Dec 1994	Explosion, 4 dead, 18 injured, 2500 outside plant evacuated	Explosion in ammonium nitrate process area, destroying the main seven-storey process building and creating a crater about 10 m across. In addition, the explosion broke windows of buildings over 25 km away in Sioux City and was felt 48 km away.
Deer Park, Texas	Doyle (2002), Marsh (2003)	Shell	Chemical plant	22nd June 1997	Explosion and fire, blast felt 25 miles away. 30 receive medical help.	Flammable gas leak led to fire and explosion
Wuppertal, Germany	Marsh (2003)	Not available	Chemical plant	8th June 1999	Explosion, 50 injured including 20 local residents	Human error – wrong chemical added to tank during production of insecticide
Pasedena, Texas	Marsh (2003)	?Phillips	Chemical/plastics	27th Mar 2000	Explosion and fire, 1 dead, 69 injured	Chemical reaction caused explosion and fire during cleaning
Birkinnhead, UK	Marsh (2003)	Not available	Polyacrylates	16th May 2001	Fire destroyed plant, 2 injured	Major release and fire destroys the polyacrylates plant
Toulouse, France	Marsh (2003), Macalister (2005)	Total	Fertilizer plant	21st Sept 2001	Explosion, 30 dead, 2500 seriously injured.	France's worst industrial accident, but cause never established
Geismar, Louisiana	Doyle (2002)	Shell	Chemical plant	12th Feb 2002	Explosion and flash fire, 1 dead, 1 injured	Not available
Totalt					***3674 dead/303542 injured/7200 evacuated***	

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Railroad incident	Information source	Operator	Type	Date	Description of event/fatalities/injuries/evacuations	Reported cause
Bogalusa, Louisiana	NTSB (1995)	Vicksburg Chemical Company	Derailment, hazardous leak	23rd Oct 1995	Ruptured freight tank. 4710 people treated in hospitals, 81 admitted, 3000 evacuated	Derailment led to rupture of freight tanks and leakage of nitrogen tetroxide, forming vapour cloud
Sweetwater, Tennessee	NTSB HZB/98-02	Norfolk Southern Railway Company	Freight tank fracture	7th Feb 1996	Circumferential fracture on freight tank, 4 injured, c. 500 residents evacuated	Freight car fractured in two, releasing flammable 8000 gallons of toxic material
Tennessee Pass, Colorado	NTSB RAB/98-08	Southern Pacific Lines	Derailment hazardous leak	21st Feb 1996	Derailment, 2 drivers dead, 1 injured, 4 families evacuated	Runaway train led to derailment, rupture of freight tanks and major spillage
Selkirk, New York	NTSB HZB/98-03	Consolidated Rail Corporation	Freight tank fracture	6th Mar 1996	Circumferential fracture on freight tank, 1 injured, no evacuations	Catastrophic failure of freight tank releasing liquefied propane that ignited in large fireball
Alberton, Montana	NTSB RAB/98-07	Montana Rail Link	Derailment, hazardous leak	11th April 1996	Ruptured freight tank, hazardous chemical leak, circa 1000 evacuated, 1 dead on train, 350 treated for gas inhalation, 123 serious	Derailment led to rupture of freight tanks and spillage of chlorine and potassium hydroxide solution
Memphis, Tennessee	NTSBHZB/98-04	Illinois Central Railroad	Crack in tank	2nd April 1997	Crack and release of hazardous material, c. 150 (26 houses) evacuated from ½ mile radius	Hydrogen-assisted crack in repair weld led to release of corrosive liquid and vapour cloud
Crisfield, Kansas	NTSB/RAR-00/01 PB2000-916301	Burlington Northern & Santa Fe Railway Co.	Derailment, hazardous leak	2nd Sept 1998	Ruptured freight tank, release hazardous material, c. 200 evacuated within 5-mile radius	Derailment led to rupture of freight tanks and release of hazardous materials and fires
Louisville, Kentucky	NTSBHZB/00/02	Matlack Inc	Freight incident	19th Sept 1998	Hazardous material release, 2400 evacuated from factory, 600 remain indoors, 7 minor injuries	Chemical reaction during cargo transfer, human error.
Whitehall, Michigan	NTSB HZB/00/03	Quality Carriers Inc	Chemical reaction	4th June 1999	Chemical reaction, 1 dead, 1 injured, 11 evacuated from the plant	Chemical reaction during cargo transfer, human error.
Riverview, Michigan	NTSB/HZM-02/01 PB2002-917002	ATOFINA Chemicals Inc	Pipe fracture, gas leak & explosion	14th July 2001	Pipe fracture, releases poisonous, flammable gas, 3 dead, injuries and c. 2000 residents evacuated	Unloading line of a railroad tank car fractured and separated, with release of methyl mercaptan, a poisonous and flammable gas. Gas ignited, fire ball
Minot, North Dakota	NTSB/RAR-04/01 PB2004-916301	Canadian Pacific Railway	Derailment, hazardous gas leak	18th Jan 2002	Rupture freight tank and release of gas and vapour cloud, 1 resident dead, 11 seriously injured, 322 minor injuries, 11600 people affected by vapour cloud	Train derailed, catastrophic rupture of freight tank and release of anmucila gas and vapour phase
Freeport, Texas	NTSB/HZM-04/02 PB2004-917003	BASF Corporation	Freight tank rupture	13th Sept 2002	Rupture of freight tank, 28 injured, residents within 1.5 miles evacuated for 5 ¾ hours	Catastrophic rupture of freight tank and explosion at transfer station release hazardous waste. Major damage, with loss of transfer station and buildings
Tamaroa, Illinois	NTSB/RAR-05/01 PB2005-916301	Canadian National Freight Train	Derailment, hazard material	9th Feb 2005	Derailment led to leak and fire, no injuries, 850 residents evacuated	Derailment causing leak of methanol from freight tanks, which ignited. Acid released from other tanks
Calamus, Iowa	NTSB/HZM-04/01 PB2004-917003	River Valley Corporation	Cargo tank	15th April 2003	Tank rupture, 1 dead, 1 injured	Sudden failure of cargo tank rupture releasing corrosive liquid/gas. Poor welding & inspection found
Middleton, Ohio	NTSB/HZB-04/01	Amerigas Corporation	Cargo tank	22nd Aug 2003	Freight tank failure, 5 treated, circa 100 evacuated from plant	Cargo tank fracture releasing poisonous and corrosive gas
East St Louis, Illinois	NTSB/RAB-05/04	Alton & Southern Railway Company	Train collision, hazardous release	21st Sept 2004	Hazardous materials release, c. 140 evacuated, no injuries reported	Remote control collision in yard and hazardous materials release
Pico Rivera, California	NTSB/RAB-05/02	Union Pacific Railroad	Derailment, hazardous release	16th Oct 2004	Derailment, freight trains strike houses, circa 100 people evacuated. No injuries reported	Derailment of freight cars, some hitting homes, rupturing tanks and releasing diesel fuel
Totals					*9 dead/5441 injured/10453 evacuated*	

Table 19. Significant American hydrocarbon related railroad accidents/incidents involving death or injury (based upon NTSB figures refer website).

Table 20. Above ground storage tank incidents between 1951-2003 resulting in fatalities and/or casualties (based upon Persson & Lönnermark, 2004 but including Clark et al., 2001).

Location	Date	Facility	Ignition source	Casualty Figures
Sestarca, Bilbao, Spain	1967	Crude oil storage tanks	Rail tankers exploded	1 dead, 8 injured
Amsterdam, Netherlands	20/11/1969	Petrol storage tank	Not available	1 injured
Czechowice, Poland	28/8/1977	4 crude oil storage tanks involved	Lightning	33 dead (most firefighters)
Spain	1972	Gasoline storage tank	Smoking	1 dead
Ras Tamura, Saudi Arabia	22/8/1979	Aramco refinery storage tank exploded and was followed by fire	Not available	Fire burned for one day. 2 dead, 6 injured
Hrida, Germany	20/9/1979	Refinery tank	Not available	1 injured
Amsterdam, Netherlands	29/9/1979	½ full storage tank in port area	Not available	1 dead, 2 injured
Cork, Ireland	1/3/1981	2 fuel storage tanks	Operator sampling	1 dead
Tacoa, Caracas, Venezuela	19/12/1982	2 heating oil storage tanks	Not available	150 dead
Bogota, Columbia	23/12/1982	3 gasoline/kerosene storage tanks	Not available	1 dead 15 injured
Corinto, Nicaragua	30/7/1983	8 oil storage tanks	Maintenance	3 dead,
Philadelphia, USA	5/10/1983	Naptha storage tank	Explosion	4 injured
Cologne, Germany	May 1985	Several storage tanks	Not available	Area evacuated.
Naples, Italy	1985	Aviation fuel storage tank	Overfilling	5 dead, 170 injured
Pretoria, S Africa	27/5/1985	Petrol tank	Not available	3 firemen dead, 7 injured
Chicago, USA	23/12/1986	Gasoline storage tank	Explosion	1 dead
Lyon, France	1987	14 tanks diesel storage tanks	Not available	2 dead
Chicago, USA	14/9/1987	Fuel storage tanks	Explosion	2 dead, 3 injured
Port Arthur, Texas, USA	1988	4 gasoline storage tanks	Not available	8 dead, 8 injured
Sines, Portugal	27/8/1988	3 tanks	Maintenance	2 dead, 3 injured
Qingdao, China	12/8/1989	Oil depot, 6 tanks	Lightning	16 dead, 70 injured
Sandwich, Mass, USA	5/8/1989	2 fuel oil tanks	Maintenance	2 injured
Oklahoma, USA	1989	3 tanks	Worker	Worker using lighter ignited fuel, 3 tanks badly damaged. 3 dead
Port of Tampa, Florida, USA	May 1990	Gasoline tank	Explosion	1 dead
Houston, Texas, USA	8/7/1990	2 tanks	Explosion	17 dead, 5 injured
New Orleans, Louisiana, USA	1992	Crude oil storage tanks	Not available	2 dead
Texas, USA	1992	Not available	Human	1 dead, 4 injured
Wyoming, USA	8/8/1992	More than 100 tanks	Not available	4 injured
Nenjing, China	21/10/1993	Gasoline storage tank	Overfilling	2 dead
Delaware City, USA	17/7/1994	2 oil tanks	Lightning	6 firefighters injured
Ueda, Nagano, Japan	11/10/1994	Petrol storage tank explodes, igniting 3 other tanks	Not available	1 dead
Dronka, Egypt (Clark et al., 2001)	2/11/1994	Aviation fuel storage tanks	Lightning	469 residents of village killed (Ash, 2006; Clark et al., 2001)
Addington, Oklahoma, USA	11/8/1995	Crude oil storage	Lightning	2 dead
San Juanico, Mexico	11/11/1996	2 gasoline storage tanks	Faulty valve	4 dead
Hyderabad, India	Sept 1997	LPG, kerosene & petroleum storage tanks	Explosion	34 dead, 100 injured
Israel	Nov 1997	Diesel storage tank at refinery	Explosion	Diesel storage tank blew up at refinery. 1 dead
Calgary, Canada	9/8/1999	Oil, diesel fuel, jet fuel, propane storage tanks	Fire	2 dead
Kansas, USA	4/9/2001	Oil tank	Human	1 dead
Duson, LA, USA	30/11/2001	Crude oil storage tank	Explosion, cause not determined	1 boy badly burned
Dexter, KS, USA	7/6/2002	2 oil storage tanks	Explosion	1 injured
Turkey	28/7/2002	9 LPG tanks	Not available	5000 evacuated
Dunbar, S Africa	17/10/2002	Fuel storage tanks at bitumen factory	Not available	1 dead, 6 injured
Gdansk, Poland	3/5/2003	Gasoline tank	Tmobile telephone	3 dead
Buncefield, Hertfordshire, UK	11/12/05	Fuel storage depot	Overfilling	43 injured
Totals				*778 dead, 426 injured, >7000 evacuated*

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(Cont.)

HSE

Health and Safety Executive

An appraisal of underground gas storage technologies and incidents, for the development of risk assessment methodology

This report was commissioned by the Health and Safety Executive to help assess the safety issues associated with the underground storage of natural gas. This has arisen because of the need to consider a number of applications submitted by various operators in the UK who wish to develop such facilities. The rising numbers of applications are as a result of UKCS oil and gas reserves showing rapid decline, to the extent that the UK became a net importer of gas during 2004. The Government recognises that the UK faces an increasing dependency on imports, yet has very little gas storage capacity and is, therefore, at a very real risk of supply shortfalls. It notes that the UK's capacity to import, transport and store gas and LNG efficiently has to be improved and this will require greater investment in new, timely and appropriately sited gas (and LNG) supply infrastructure, part of which is likely to include (safe) onshore underground (natural) gas storage (UGS) facilities.

This report and the work it describes were funded by the Health and Safety Executive (HSE). Its contents, including any opinions and/or conclusions expressed, are those of the authors alone and do not necessarily reflect HSE policy.

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APPENDIX 9

SPE/IADC 92647

Urban Operations: Drilling and Completing a Gas Well on a Downtown University Campus

D.W. Spady, SPE, Columbia Natural Resources, LLC., and J. Michael Poole, Union Drilling Inc.

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This paper was prepared for presentation at the SPE/IADC Drilling Conference held in Amsterdam, The Netherlands, 23-25 February 2005.

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Abstract

It started as a simple concept: donate to the local university a wellbore, through which they can produce their own gas to offset rising utility bills. The final result - a successful well which required a tenuous journey through geological identification, regulatory hurdles, resident opposition, logistical restrictions, location stability concerns, drilling surprises and reclamation procedures. The process brought together a regional independent gas producer and six of its major vendor partners, each donating their portion to a project that earned strong community support. This paper will journal the steps of the process, as well as outlining a template for future projects in sensitive environments.

History

Charleston, the Capital city of West Virginia, lies along the banks of the Kanawha River as it flows west and north to the Ohio River. This river has been an active waterway for many years, providing a critical transportation link to the central part of the state on the western flank of the Appalachian mountain range. The first discovery of natural gas in the state was in 1815 by Captain James Wilson, while drilling for brine about a mile from where the Capitol building now stands. Over the years, the downtown area surrounding that discovery well has grown to include residential and commercial neighborhoods. In 1947, Morris Harvey College began construction of a new campus on the riverbank opposite the State Capitol, and some years later, in 1978, it changed its name to The University of Charleston. Three blocks south of the main campus, also in the neighborhood of Kanawha City, is a multipurpose athletic field owned by the University and known as Blackwell Field.

The geology under Blackwell Field is similar to that of most of the exploration prospects in the area, containing Mississippian and Devonian age sedimentary formations above the underlying Devonian Shale. Regional offset wells and geologic data verified that both the clastics and shales should produce high BTU value gas with minimal water or oil. Indications were that the pay thickness would be above average, giving an economically viable well in an area that had seen no drilling activity for a century due to the expansion of the city core.

The University's rising cost of campus utilities was observed and noted by the President of Columbia Natural Resources (CNR), who is a member of the Board of Trustees of the University of Charleston. It was suggested to the University management that perhaps CNR could drill a producing gas well on Blackwell Field if the University had title to the mineral rights. The idea of a gas well to reduce utility costs was greeted with enthusiasm by Dr. Edwin Welch, UC President. In early fall 2003, an initial meeting was held at the President's office on campus to discuss the possibility, which was greeted with enthusiasm all around. Knowing that there would be a non-trivial public information and response process, the next steps were to refine the geological model, conduct a title search to prove ownership, review city and county statutes relating to the drilling of a gas well, and plan the community interactions.

Long Range Planning / Regulatory Approval

Initially the list of regulatory bodies was substantial, but after doing some research, several were not relevant or superceded by municipal code. As it turned out, the permitting process required only a shallow well permit from the WV Department of Environmental Protection, and a building permit from the City of Charleston, which required a Special Permit from the city's Planning Department. If the well were within 500 feet of a residence, a zoning variance would also be needed. Initial planning of the well location was to align the well with the road entrance gate of the sports field, well within the 500 foot residential proximity zone.

The first of two public meetings was hosted by the University and held on October 29, 2003. There was a significant amount of opposition primarily from the residential landowners in the adjacent neighborhood. Kanawha City is a district of Charleston that stretches along the south bank of the river, which in many places is about 10 city blocks wide. This narrow neighborhood contains a large hospital, the University of Charleston, a ball park which is home to the Single A Charleston Alley Cats Baseball Club, multiple large office buildings, prime waterfront properties, and many other residential dwellings. Within 1000' of the proposed well was

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a Church, a Montessori School, and an eleven floor office building.

At the first public meeting, the residents were most concerned about the following five issues:

1. Noise
2. Safety during the drilling process
3. Inconvenience (traffic, closure of ball fields, etc.)
4. Safety after the well is complete (vandalism, terrorism, children playing with equipment, etc.)
5. Setting a precedent for drilling more residential wells in the area

After considering these issues, it was examined whether the well could be moved as far away from the residences as possible (to the west), reducing the amount of noise and traffic by having a second entrance to location for non-construction traffic. This would have an adverse affect on the use of the sports field, as a more westerly location would be where soccer was normally played, but a key benefit of moving the well to the west would be the possibility of being more than 500 feet from the nearest residence, thus eliminating the need for a variance from the City's Board of Zoning Appeals.

A site inspection was planned to consider the possibility and measure some distances. As as a result of that visit and subsequent discussion, it was decided that the well would be moved to the west. This action was a direct result of input by the local residents at the first public meeting.

Title work was started at this point to verify the rightful mineral ownership on the western protion of Blackwell field. Noise studies were also conducted to determine if the drilling process would be above the minimum threshold for needing a special permit or public hearing on noise pollution. The ambient noises were measured **(Table #1)**, and then compared to estimated noise levels from a drilling rig similar to the one expected on location. The findings showed that the ambient noise levels were between 48 and 85 dbA, which would be comparable with a quiet office or the inside of a moving car on a highway. Any component of a drilling rig or construction was found to be less than70 dbA at 200 feet, which would be well below ambient levels at any point outside of the sports field. **(Table #2)**

As a result of this first meeting, several of the residential neighbors spoke to the media about the perceived threats of a hydrocarbon exploitation operation in close proximity to residential housing. Examples of neighborhood issues in Hollywood, California (26 old oil wells on a high school property) and talk of explosions seemed to be the prevailing reasons to not have the project proceed. The question of real estate value also came up publicly. There was a certain amount of comment on a local radio talk show as well, but most of the opposition amounted to focusing on the few catastrophic incidents around the world that receive a large amount of publicity, versus the millions of operating hours our industry logs incident free on a daily basis.

The aforementioned Special Permit was applied for with the City of Charleston Planning Department to allow a well to be drilled within city limits. The application was to be heard by the Planning Commissions on December 3rd. At the hearing, the application would be considered, and then the members of the Commission would hear opposition to the permit.

When it was decided to move the well at least 500 feet from the nearest residence, an application to file a variance with the Board of Zoning Appeals (BZA) of the City of Charleston was no longer necessary. Confirmation of changing the location, and the subsequent non-filing for the permit occurred on Tuesday, November 11th, which was the last date to file and be heard at the next monthly meeting of the BZA. At this point, there was no turning back on the decision to place the well in the western part of the field, and all planning and placement issues were focused on the revised location.

Due to increased political pressure on various members of city council, there was also a threat to force the building permit issuance before the elected officials on the city council, as opposed to its normal approval channels at the Building Department. This would undermine the authority of the city staff and result in a very abnormal breach of procedure, but it was an idea that was discussed, probably in reaction to orchestrated political pressure. Part of that political pressure was the placement of a number of signs in the neighborhood that read: "Please...Do Not Drill [a] Gas Well [on] Blackwell Field". **(Figure #1)**

On November 20th, CNR submitted the building permit application to the City of Charleston, showing the new location of the well.

The second neighborhood meeting was held on November 20th. Prior to the residents' meeting, several discussions were held with city and state officials regarding the permitting process. Dialogue had also been conducted with the city regarding turning the street which leads to the entrance gate of Blackwell Field (19th Street) into a temporary 2 way street from its normal status of a one-way street in the direction leading into the field. In addition, construction signage, the condition of 19th street's surface, and the fragility of the sewer line which runs under it were discussed with city and Sanitary Board officials. At the second meeting it was pointed out to the neighborhood that the well was moved as far as possible away from their houses as they had suggested in the first meeting. This would result in an increase in the cost of the location pad, but it was a worthwhile tradeoff in noise mitigation. This was discussed at the meeting, as well a noise levels and ultimate use of the field. The final product on the field, after tie-in, was also discussed. To summarize, the key points expressed at the meeting were:

1. Securing the proper permits
2. Noise levels
3. 19th Street traffic (including the change from a one way to a two way)
4. Potential risks of fires or explosions
5. The affect of the well on property values
6. Completing or fracturing the well and the associated process
7. The drilling schedule
8. B&O (Business & Occupation) taxes and various commercial aspects of the gas sales and production
9. The ongoing erosion of the residential neighborhood

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Present at the meeting in an official capacity was the local City Councilperson, a representative from the Mayor's office, and the head of the city's planning department.

With the 2nd neighborhood meeting complete, the next focus was on the preparation for the Planning Commission meeting on December 3rd, as well as the logistics of preparing the drill site.

Due to the tight configuration of the location layout, environmental considerations, and the noise and fluid constraints, the rig components would need to be modified to have a completely contained, above ground fluid system. This was done by means of two large metal tanks configured in a way to allow flow of fluids, settling of solids, and containment of air flow with the use of large heavy doors on the top of the tanks. The system allowed containment of fluid and solids in both the air drilling of the well and any fluid drilling contingincies. The rig would also need to be configured in such a way to allow normal substructure and equipment access while staying back from the riverbank. In addition to staying away from the waterway, the end of the location perpendicular to the riverbank from loading because of a large storm water culvert that crossed underneath the west side of Blackwell field. Maps were drawn, distances were measured, and the prospective well location was surveyed. In preparation for the Planning Commission hearing, several diagrams were created to graphically represent the planned well. On December 1st the city determined that the extra traffic on 19th street, estimated at some 200 truckloads, should not hurt the sewer line below the street, partly due to the depth of the line being some 16 feet. We did elect, however, to run a sewer video camera through the line before and after the project. The City required that CNR post a bond for $12,995 to cover the cost of repaving the street should it be damaged.

The December 3rd hearing went as planned, with a number of residents present to oppose the project. The local paper, The Charleston Daily Mail, summarized the meeting best in its December 4, 2003 edition:

" Despite protests from residents in its neighborhood, the University of Charleston's Blackwell Field will be the site of a new natural gas well the college says won't adversely affect the community.....

.....Charleston's Municipal Planning Commission approved a special permit Wednesday for the site, the first natural gas well to be proposed in a residential area since 1981....

.....More than 80 residents have signed petitions against the gas well and some have posted protest signs in their lawns. They cite explosions of similar wells in other cities and studies that show a decline in property values as reasons the city should veto the project.

Planning commissioners were not convinced the project will be a long-term detriment to the neighborhood.

"One of the producing wells I've seen in the past couple of days is in Quarry Creek in the front yard of a million dollar-plus home and that has not been a detriment to the property value of that home," Councilwoman Mary Jean Davis said. "

After the hearing the planning and preparation proceeded quickly for a January 1st start date. Partner vendors were chosen, contracts drawn up, and the procuring of materials began. One of the solutions to reducing the number of truckloads traveling over 19th Street was to bring the gravel and stone required for the drilling pad to the site via the river adjacent to the field, rather than by road. Initially viewed as a bit of a stretch, the quotation process soon legitimized the cost of barging the stone as being in line with trucking to location. A large number of commodities, including coal, cement, stone and petroleum products are routinely barged on the Kanawha River, which is part of the Ohio / Mississippi river system managed by the US Army Corps of Engineers. A barge load of stone was ordered for a planned delivery in the first week of January. The AFE (Authorization For Expenditure) was also drawn up for the well and contribution amounts from the partner donors were suggested. Technical programs were determined, including the specifics from each of the vendors.

On Monday, December 29th, a resident who lives near Blackwell Field filed an appeal with the Charleston Planning Department requesting the Board of Zoning Appeals (BZA) to reverse the decision of the Municipal Planning Commission of December 3rd. The filing of the appeal was just within the 30 day period allowed. The BZA meets only once per month and has a 30 day cutoff before its meeting for determining the agenda items, which made the next available meeting of the BZA at which this appeal could be heard as February 19th. This was a setback to the timing of the well, which was originally planned to be during the coldest part of the year to ensure firm soil and a more stable field for the drilling pad and access road. According to the filing the appeal was based on the following 6 reasons:

1. Potential danger to families, homes, and students who use Blackwell Field
2. Noise Pollution
3. Possible environmental impact
4. Declining property values which would result in loss of tax revenue
5. Increased liability for property owners as well as the University of Charleston
6. Establishment of a precedent for future drilling in other residential neighborhoods within city limits

The decision was made very quickly to postpone all operations on the project until after the February 19th BZA hearing. Fortunately, a buyer for the barge load of stone was found while it was being shipped to the site.

It was decided that CNR and UC would have legal representation before the BZA, so the preparation agenda for the February 19th hearing fell to the law firm. Work was concentrated in three areas:

1. Showing what the physical appearance of Blackwell Field should look like when the project is over. This involved photographing the field and superimposing the expected facilities into the picture for a visual display to the BZA.

2. Conducting research on wells currently operating in the City of Charleston and other cities in West Virginia. Part of this process was researching the permit dates and photographing the wells and facilities.

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3. Demonstrating the professional and safe manner in which our company and industry operate locally.

In the process of doing the research for the hearing, it was surprising to see how minimal the effect of the final well facilities would be on the field. As an example, in order to see the superimposed wellhead as seen from MacCorkle Avenue in **Figure #2**, look for the green spot in the exact center of the photo. Compare this superimposed "before" photo with the actual reclaimed site as seen in **Figure #3**, taken from the same vantage point (note the wellhead is caged with a fence).

One of the critical factors in the project was the ability of our drilling service and supply partners to participate by donating services or goods. Key to this ability was a seasonal slowness in the industry that normally occurs in the months of January and February, when the freeze / thaw cycle makes remote working conditions difficult. After dialoguing with all of our partners, it appeared that for most of them the delay would still work with their schedules. With a proposed start date of February 20th, the donors would still have a window of availibility for their equipment. With the anticipation that the appeal would be overturned by the BZA, and the knowledge that the window of availability of our donors was limited for the current year, a new project start date of February 20th was set, with major location construction to begin on March 1st.

The hearing on February 19th went as expected, with a strong opposition from the neighborhood, but solid support from both the City Planning Commission that initially approved the project, the local City Councilperson, and the office of the Mayor. The residents' appeal was overturned by a unanimous 4-0 decision. For the residents to reverse this decision it would require an appeal to circuit court, as well as the corresponding bond. Immediately a Building Permit from the City was issued based on the decision of the BZA. Construction could begin.

Several critical environmental (neighborhood) factors affected the logistics and planning of this well. Firstly, the activities on the field had to flow in a consistent, time sensitive manner, as we stated to the community that the process would take approximately 22 days with no breaks. This would require pre-planning and staging off location. Secondly, as the site was in an urban area, once drilling commenced there needed to be 24 hour supervision on the site. Thirdly, the amount of road traffic needed to be kept to a minimum, so redundant trips were eliminated and any materiel transport to the location other than by truck was examined.

The major construction equipment was operated by our location building partner and was quite booked up at the time the construction permit was issued, so it was decided to push the start of most construction back to March 1st, then work as quickly as possible through the entire process with a full compliment of equipment and personnel. This decision, fortunately, did not affect the drilling contractor, whose rig earmarked for the job was engaged until the first week of March. Likewise, the service rig contractor, the pumping and the well logging contractors were able to work with that schedule. Any significant further delays, however, for any of the service contractors, would put their ability to provide donated services in jeopardy. We planned a pre-spud meeting on Friday March 5th. By that date we intended to be finished building the road and location. Contractors, subcontractors, regulators, UC staff and CNR personnel would attend the pre-spud meeting. At the meeting, all aspects of the operation would be discussed including safety, environment, logistics and neighborhood awareness. Since CNR has an ISO 14001 certified environmental management system, all operations discussed at the pre-spud had to be in full compliance with this standard. Also on the agenda for the pre-spud meeting was the discussion of the type of vehicles allowed only on 19th street, use of the 19th Street and MacCorkle avenue intersection, staging loads and visitor parking.

The issue of 24 hour supervision on the site was handled through the use of a wellsite trailer, in which the Project Manager or Drilling Engineer would reside for the duration of the project. Once the completion and flowback processes started, a security guard would be posted during the evening hours. The rig perimeter would be fenced so that no bystanders could gain access to the operations on and around the rig. The entire Blackwell Field site would also be kept locked as a primary means of site security.

To reduce the amount of road traffic, two things were done. First the stone for the location was all shipped to and removed from location via barge on the Kanawha River. This eliminated about 100 truckloads from the street. Secondly, all light traffic (including supervisors, rig crews and visitors) would be directed to the Columbia Transmission (TCO) office building parking lot directly west of the location. To facilitate entry onto Blackwell Field from the paved TCO parking lot, a lockable person-gate was made in the chain link fence on the west side of Blackwell Field. This gate led via a gravel path to a 20' x 20' tent that would serve as an area from which visitors could watch the activities of the operation. **(Figure #9)** By using this approach, the 19th street entrance would not be clogged with light vehicles, allowing the heavy truck traffic to come directly onto location via the 19th Street gate. Photographs before location construction commenced, such as the first photograph in **Figure #17**, were taken to document the process.

Location & Conductor Pipe Preparation

On February 24th the on-site preparation began. A location stake marking the exact well location was verified, and then a large metal pin was driven into the ground. This would allow the location to be built over the pin, and then found after pad construction with the use of a metal detector. On Friday, February 27th the first rolls of geo-textile were laid down. The geo-textile, a black thatched fabric base, permits less stone to be used in a construction process by "holding" the bottom layer of stone in place.

The base of Blackwell Field is very unstable from a civil engineering perspective. Once a sloping riverbank, it was build up with "fill" over the years to literally make a level-playing surface some 30 feet above the river level. The fill consisted primarily of fly ash produced by coal fired power plants in the region, but also had other components of clay, rock and concrete rubble. Initially, it was planned to scrape off the topsoil from the field, build the location, and then replace the topsoil once the project was complete. Upon more consideration, it was decided that the ground under the topsoil was even less stable than the topsoil, and that location would

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be built above the field, utilizing the topsoil as a contiguous layer to build upon. Any sinking or settling would be filled upon reclamation.

As seen in **Figure #4**, in order to get the equipment onto location to spread the stone unloaded from the barge, an access road was built from the 19th Street entrance gate to the field using gravel and stone that was trucked in. Steel plates, as seen in **Figure #5**, were also placed on the street at the high traffic gate area to protect the fragile sewer lines. Once this road was completed to the barge unload area, the heavy equipment, consisting of a large track hoe and dozer, were moved in. The remainder of the location stone was then brought in by river barge and offloaded onto location using a crane. The river level was lower than anticipated, so the travel distance of the work barge crane was greatly increased. This in turn dictated that a smaller bucket be used on the crane, adding significantly to the unload time. When each crane load of stone was placed on location, it was spread out over the geo-textile and compacted. **(Figure #6)**

Building a stable surface location was one factor that was accounted for, but a second and equally critical factor was the stability of the rig itself during drilling and the ground in the immediate vicinity of the wellbore casing. Normally, a surface hole or conductor hole is drilled with the 20" bit from the rig, pumping air or fluid through the bit and circulating up the outside of the hole as it was being drilled. When drilling in fly ash, however, there is nothing to hold the hole from eroding as the conductor borehole is being drilled, and the continuous erosion of the borehole walls near surface would probably spread until it jeopardizes the footing of the rig itself, potentially causing a catastrophic collapse of the derrick. In addition to the rig collapse issues, conductor drilling was complicated in that once about 40 feet of depth is reached, a potential water influx from below the base of the river bed could be encountered with a resulting massive flow of water further damaging the borehole and stopping the air drilling process.

In order to mitigate both of these situations, a method was used similar to what had been used in locations that were in very close proximity to stream and riverbeds in Southern West Virginia and Western Virginia. As pictured in **Figure #7**, a drilling rig that utilizes the Concentrix® bit system was used. This is essentially a concentric system that drills while planting the pipe that serves as the conductor. A 16" conductor pipe is fitted with the Concentrix® bit system consisting of a bit tooth ring and bushing welded to the first joint of pipe, which locks into a bit that is lowered through the inside of the conductor. In **Figure #8** it can be seen that the bit has holes allowing it to circulate the fluid from the bit face back into the annulus of the 4 1/2" drill string and 16" conductor. At the rock face, both the bit and the ring / bushing assembly rotate, but the conductor pipe immediately above the ring does not, it is simply pushed into the rock as the hole is created. When one joint or length of conductor is drilled, the drill bit is pulled out, another joint of 16" is added and welded on, and the bit is run back in the hole to continue drilling. By using this system, hole stability at surface was achieved as well as the potential encroachment of water was stopped downhole. Drilling rates were as high as 5 feet per minute using this system.

Conductor hole drilling started on Monday, March 8th. The subsurface of the location had little more than fly ash in it, and the casing almost dropped through the fill. Only occasionally would the percussion air hammer on the bit activate, noting a harder formation and slower drilling. On Wednesday, March 10th at about 47' a substantial amount of water flow was noted, as well as creek gravel. The drilling process was essentially inside of pipe, so we were able to carry on. At the next connection, with 68' of conductor in the ground, the hole was dry. On Thursday March 11th, the final joint of conductor pipe was drilled to 86' and the rig was moved out. The last drilling of the 16" was noted to be dry, and there was excellent conductor stability at surface. A six-foot length of 8' diameter steel was placed around the 16" conductor pipe to act as a cellar. Cement was placed in the bottom to serve as a base of the cellar. This would allow ease of work on the wellhead and better placement of any valves used in drilling. At this point the issues of surface stability and downhole water isolation were successfully negated, and the process was ready for drilling the main borehole.

Drilling

On March 11th, the drilling rig moved in and began rig up. Before the mast was raised, rig mats were positioned on either side of the cellar for the mast to rest on, adding more stability overall. The return air system for the rig went into two above ground steel pits. The primary pit included an elbow and internal piping to knock some of the velocity out of the flow. From the primary pit the fluid migrated to the secondary pit where the flow line ended. The pits were designed both to hold cuttings and reduce open air flow on location. To further enhance this process, hinged ¾" plywood lids were mounted on the top of the pits to cut any dust flow. **(Figure #11)**

The rig up and rathole drilling was completed on March 11th, and drilling out of the 16" conductor with a 12 3/8 hammer bit commenced at 12:30 a.m. on March 12th.**(Figure #9)** The 12 3/8" hole was drilled to 346' on March 12th, 7 joints of 9 5/8" casing was run and a 150 sack cement job was pumped. Water circulation was seen back to surface, but cement returns were not observed, so an additional 40 sacks were used to grout down the annulus.

On March 13th, drilling began with an 8 7/8" diamond enhanced percussion hammer bit. At 670' a stream of water was encountered that measured a 2 ½" flow on surface. The drilling system was converted to a mist system using drilling soap and drilling continued until 1070', when all available water storage was used up on location. The drill string was pulled off bottom while the rig waited for extra tankage. Additional tanks were brought into location, and the drill string was staged to bottom while unloading the hole. The 8 7/8" hole reached total depth at 1250' on March 14th and 32 joints of 7" casing was run to the top of the Big Lime formation. A 100 sack cement job was performed and cement was circulated back to surface. The plug was down at 11:45 pm on the 14th, indicating a successful cement job completed.

Drilling was resumed on March 15th with a 6 ¼" tricone bit drilling out the cement and shoe. The hole was cleaned and dried and drilling new formation commenced. Fifteen feet later, at 1265', the air pressure spiked to 500 psi and stayed there. At first it was thought that the bit was plugged , but

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upon surface examination, it was not. There was, however, evidence of salt water on the bit. The drill string was run back in the hole to 729" and a 5" to 6" stream of water was returned to surface! The string was pulled all the way up to 365' before the top of the water was reached. Upon testing, the water was found to be 9.5 lb/gal brine. The initial objective was to drill 25 feet into the top of the Big Lime formation to set the 7" casing, assuming that the rest of the Big Lime formation was dry, and the hole could be drilled dry using air (dusting) to total depth.**(Figure #10)** With this much water encroachment, it would be impossible to drill with air, so it was decided to drill out on fluid past the Injun sand, cement 5 ½ casing into the well, and then drill out to TD with a slimhole assembly. The Devonian shale target zone cannot be drilled or completed using fluid, so the water zones had to be cased before the final section of the hole.

There was still a large quantity of brine on location, so having a useable drilling fluid on location was not an issue, however the method of pumping that drilling fluid was. A mud pump was needed and one was brought in from Norton, Virginia some 4 hours away and rigged up behind the steel pits and the rig **(Figure #11)**. On March 16th, fluid drilling began with a 6 ¼" hole and it reached a final depth of 1531' on March 17th. The hole was cleaned out and 5 ½" casing was run, with the bottom 7 joints of casing cut and welded to fit into the 6 ¼" open hole. The casing was cemented into place with 65 sacks of cement, with the plug down at 6:15 am on March 18th.

A major deviation from the original well plan was now in effect. The drilling environment went from a conventional hole size to a slimhole drilling operation. The 4 ½" drill pipe on the rig was swapped out with a 2 3/8" slimhole string courtesy of the service rig provider. In addition to the smaller slimhole style drill string, the kelly bar, kelly drive bushings, slips, elevators, tongs, rotating control head and other harware all needed to be changed.

The smaller drill string inside diameters and the tighter annular tolerances on the outside of the drill string created an increased friction pressure which dictated the need for a significantly higher pressure air system on the rig. Typically, a conventional air system used for Appalachian Basin drilling consists of three skid-mounted units that collectively produce approximately 2000 standard cubic feet of air per minute at continuous operating pressures of up to 375 psig. The slimhole environment of this well would require similar volumes, however, the pressures would near 750 psig. To meet this need our compressor provider donated the use of two Ingersoll Rand 1170 / 350 model air compressors. Air volumes from these two compressors were fed into a new technology Ariel high-pressure air booster owned by the drilling contractor. The combination of this equipment yielded air volumes in excess of 2300 cubic feet per minute at continuous deliverable pressures of up to 800 psig. Now the Blackwell Field location contained a drilling rig with a conventional air system, a duplex mud pump, and a high-pressure air system!

A 5 ½" x 7" swedge had been rigged up on the top of the casing to hold an orbit valve for use in annular diversion from the wellbore. When the 4 7/8" tricone was run in for drilling the next section of hole, it would not fit through this restriction, so a 4 3/4 " bit was needed. Finally, on March 19th the 4 ¾ " bit was run in the hole and drilled out the insert and cement. The good news was that upon cutting new formation, it appeared to be very dry. This verified that we had put all of the water filled zones behind pipe.

Drilling out on the 4 ¾" hammer bit was very arduous, due to the sensitive nature of the slim hole string and bit. Drilling was very slow, averaging several hours per foot for the first 24 hours. In addition to slow drilling, the morning of March 24th turned out to be very cold and one of the booster pumps froze off, halting drilling operations again. The good news was that at 1635', in the Weir formation, a gas odor was noticed, and that gas odor continued while slowly drilling and waiting on compressors to thaw.

On March 24th the drilling rate picked up, with close to 100' in 24 hours near the end of the hole. The hole reached total depth on the morning of March 26th, at 4109'. The gas odor and flow persisted from the uphole formations.

The well was logged on March 26th, using the standard Appalachian logging suite measuring induction, Neutron, density, temperature and noise. Before logging the well, the gas flow from the uphole zones was gauged to be 84,000 mcf/day.

The well drilling was complete, and by all indications from the logs and the flow of the uphole zones, it had the potential to meet expectations. The process went well from a technical point of view, but there were some curves thrown into the operation thanks to unexpected brine from the Big Lime formation. The drilling process was completed with 128 joints of 3 ½ " casing being cemented into the well with 60 sacks of LiteCRETE® cement. The plug was bumped at 6:30 a.m. on March 27th, signaling the completion of a successful process. The rig crew took a well deserved weekend off while we waited on cement.

Completion

On March 29th the drilling rig began rigging down, and on April 1st, the service rig began rigging up. Our cased hole logging and perforating partner ran a set of bond logs, which showed good cement bond at the bottom of the well and a clear cement top at 2288'. With such a small annulus, good cement was critical, and the cement top was designed to be well below the productive horizons of the Weir Sand, Berea Sand, and Pocono Shale. These formations were left to produce, unstimulated, up the 3 ½" casing annulus.

Perforation of the Lower Huron horizon of the Devonian Shale was conducted on April 3rd, with 45 holes being shot in selected intervals between 3324' and 3842'. Due to the diameter restriction of the well, a bi-wire gun system was used successfully.

On Saturday, April 4th, a Nitrogen Frac crew was rigged up to perform a fracturing operation **(Figures #12 & #13)**. The Lower Huron was stimulated using over 2 million SCF of straight Nitrogen. Perforation balls were used to divert the flow, but with a relatively high friction pressure, no noticeable effect of the balls was seen. As soon as the fracturing crew was rigged out, flowback began. Almost immediately upon flowback a strong odor of natural gas was noted, signaling that the perforation balls had indeed worked by plugging some of the more high rate perforations early in the treatment, allowing

D2-254 (Cont.)

the natural gas to flow back quickly. The 24 hours open flow test indicated a flow rate of 297 mcf/day.

In the final analysis, the well is expected to produce some 70 mcf/day into the pipeline for the University's benefit. By all accounts, the drilling and completion segments of this project were a complete success.

Reclamation

Flowback of the Nitrogen in the well continued for another week, then the well was shut in and completion equipment removed. On April 13th, the reclamation process began by removing the stone from the location and piling it near the river bank in preparation for shipping by barge.

Trenching also began on the pipeline to carry the gas from the facilities pad, at the back corner of the field, to the main Allegheny Power gas distribution line on the south side of MacCorkle Avenue.

On Friday, April 16th, the barge arrived to remove the stone from location. **(Figure #14)** Due to a significantly higher water level on the river, the process was completed in one day. The higher water level allowed the barge to get closer to the field, and not have such a long travel for the crane bucket. In the photo above the crane from the barge can be seen removing the stone from location. Although very un-typical for land based operations, barging location stone on and off location turned out to be very cost effective, and greatly reduced the chance of damage to city streets due to truck loads.

Blackwell Field, once the stone was removed, did not seem to be too worse for wear. The damage was minimal, partially due to the extensive use of geo-textile, and continual grooming of the location and road after large loads crossed the surface. The area was scraped, new topsoil was added, and grass seed was applied. The line was traenched to the facilities area and the facilities were installed. By the first week of June the sports field was returned to its pre-well condition and activities are being carried out once again on the surface. The wellhead and the facilities will be completely enclosed in a chain link fence, including the top. **Figure #15** shows the reclaimed pipeline tie-in from the facilities to the main distribution line running south of the field. Minimal water is expected in the gas, and no oil, so the facilities include a small dessicant dryer and a drain tank, plus various meters and regulators. A facility access road goes along the river edge of the property where the fence once ran. The field was re-seeded around the wellhead **(Figure #16)** and it is currently back to its full use as a sports field.

Benefits

This project has given a myriad of benefits. First and foremost, the University of Charleston will reduce their overall gas budget by about 25%. When the project was being planned, it was expected to save the University some $87,000 per year. Current pricing levels of natural gas coupled with a better than expected well performance have already doubled this figure. With a 60 year well life expected, this amounts to a significant value to the University.

Secondly, this project let us showcase our industry to the community.**(Figure #17)** Not only are we a safe and responsible industry with a small environmental footprint, we can also be good corporate citizens. Consider what one of the neighbors said to the Charleston Gazette reporter on March 26,2004, after the drilling was complete:

" "I think most of the residents realized after the hearing we had exhausted every effort possible." Said Fisher, who is pastor of South Ruffner Presbyterian Chruch. "And I began to watch when they started to drill, and I believe they are doing everything possible to make it safe." Fisher said he stopped by the site before a recent Wednesday evening church meeting, and workers offered to halt drilling during the service. "I told them it wouldn't be necessary, it wouldn't interrupt us." Fisher said."

The small tent set up just a few feet from the edge of location saw as steady stream of visitor to the site. Some were surprised, all were impressed.

Thirdly, the UC well brought together a group of CNR personnel in a team with some of our key vendors, allowing us to plan more wells as a team in sensitive areas such as cities, State and Federal forests and game reserves, and sensitive watersheds. This interaction, partnership and common donation of goods and services will not be soon forgotten in the memory of those participants, as we recall the donation we have all given to our University, our city and our industry. As a direct spinoff of this project, CNR has entered into an agreement to lease the City of Charleston's oil and gas rights. This next phase of civic activity will involve drilling more wells within city limits to tap into the geologic formations that have until now been difficult to access from an environmental impact point of view.

Lastly, this process has provided a safe, reliable template for sensitive locations. This simple template can be transported and reformed in many different settings. Following are the six steps that we recommend should be followed in urban or environmentally sensitive locations:

1. Do diligent research to determine potential pitfalls outside of the normal operating expectations. Planning is key.
2. Spend time with the jusridictional authorities and elected officials to ensure that they fully understand the process and are comfortable with your abilities.
3. Allow plenty of contingency time for permits, regulated processes, hearnings and appeals.
4. Be ready to begin operations as soon as approval is granted. Keep the momentum.
5. Invite industry partners and vendors to be a key part of the process.
6. Welcome the public to safely view the process once operations are underway. Have personnel on site to answer questions about the process.

Conclusion

Refining practices we use every day, we proved that our industry is as safe, professional and as "footprint competitive" as any other source of energy. This proof was all carried out in a very mature basin that has over a century of public opinions already in place regarding our industry. In spite of some large obstacles and public perception, it was

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demonstrated that the modern oil and gas industry can easily co-exist in some of the most high profile areas. For the participants on the project, the awareness level was raised, but the methods were not changed from the way things are done every day. The result was outstanding: proof that we are a professional, clean and environmentally sensitive industry that can and will conduct business in any setting.

Acknowledgements

The authors express their appreciation for the six major partners (donors) on this project:
Union Drilling, Inc. (Drilling Rig & Equipment)
Schlumberger (Cementing, Openhole Logging and Fracturing)
Twin Drilling (Location Building and Reclaimation)
Lloyd Jackson Well Service (Tankage, Service Rig, and Slimhole equipment)
Meeks Wireline (Cased hole logging and perforating)
McJunkin Appalachian Oil Field Supply (Tubulars & Hardware)

In addition, several other vendors provided products free of charge or at reduced rates to the project:
Keystone Drill Services, Inc. (High pressure air system)
North Eastern Consulting Inc. (Wellsite trailer)
Maverick Tube Corporation (Pipe)
Hughes Christensen (Bit)
S.W. Jack Drilling (Tanks)
J.W. Pit Well Servicing, Inc. (Drilling pit discharge)
Northeastern Mud Systems Company (Cuttings pit)

Also, this paper would have been missing some key details without the knowledgeable contributions of the Eddy Grey, Director of Civil Engineering; and Conrad Sansoucie, Environmental Affairs Manager at CNR LLC.

Table #1 Noise Measurements

Blackwell Field Perimeter, Base sounds (dbA)

Lowest daytime readings – Temp 66F, Clear sky

Data Point	1-2 pm w/o wind	Wind @ 5-10 mph	Traffic: Frontage Rd.	Traffic: Kanawha Ave
21st & Frontage Rd	62.3 – 75.6	70.2 – 85.3	72.8 – 82.6	
20th & Frontage Rd	60.3 – 72.8	70.2 – 85.3	72.8 – 82.6	
19th & Frontage Rd	56.8 – 73.6	70.2 – 85.3	72.8 – 82.6	
19th & Kanawha Ave	50.9 – 60.9	70.2 – 85.3		62.8 – 73.4
20th & Kanawha Ave	47.8 – 63.1	70.2 – 85.3		62.8 – 73.4
21st & Kanawha Ave	51.0 – 62.3	70.2 – 85.3		62.8 – 73.4

Data Source:
Conrad Sansoucie, Environmental Affairs Manager, CNR LLC

Table #2 Typical Rig Operation Noise Levels

Typical Equipment	dbA at Source	dbA 200 ft	dbA 300 ft	dbA 500 ft
Dozer	85	49	31	0
Backhoe	98	62	44	7
Generator	89	53	35	0
Air Compressor	101	65	47	10
Drilling Rig	98	62	44	7

Datra Source:
Conrad Sansoucie, Environmental Affairs Manager, CNR LLC

Figure #1 Protest sign, a common sight in the Kanawha City neighbourhoods after announcement of the project



Photo: Charleston Gazette

D2-254 (Cont.)

Figure #2 Blackwell Field with Superimposed wellhead for presentation at public hearing. Note the superimposed wellhead, presented to scale as seen from the street, is the small green dot in the centre of the photo.



Figure #3 Actual photo of Blackwell Field from similar vantage point upon completion of the project. Note the UC Football team are practising on the reclaimed wellsite area.



Figure #4 Initial stone hauling via truck and spreading at entrance to Blackwell Field in order to move heavy equipment into the barge unload position.



Figure #5 Steel plates that were laid at the entrance gate to protect the fragile sewer system below the street in this high traffic area.



Figure #6 Arial view of the barge containing the location stone being offloaded onto Blackwell Field.



Photo: John Sibold / Bryan Boyd Creative Group

Figure #7 Concentric drilling rig on location drilling and setting conductor.



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(Cont.)

Figure #8 Contcentrix ® Bit System and 16" conductor.

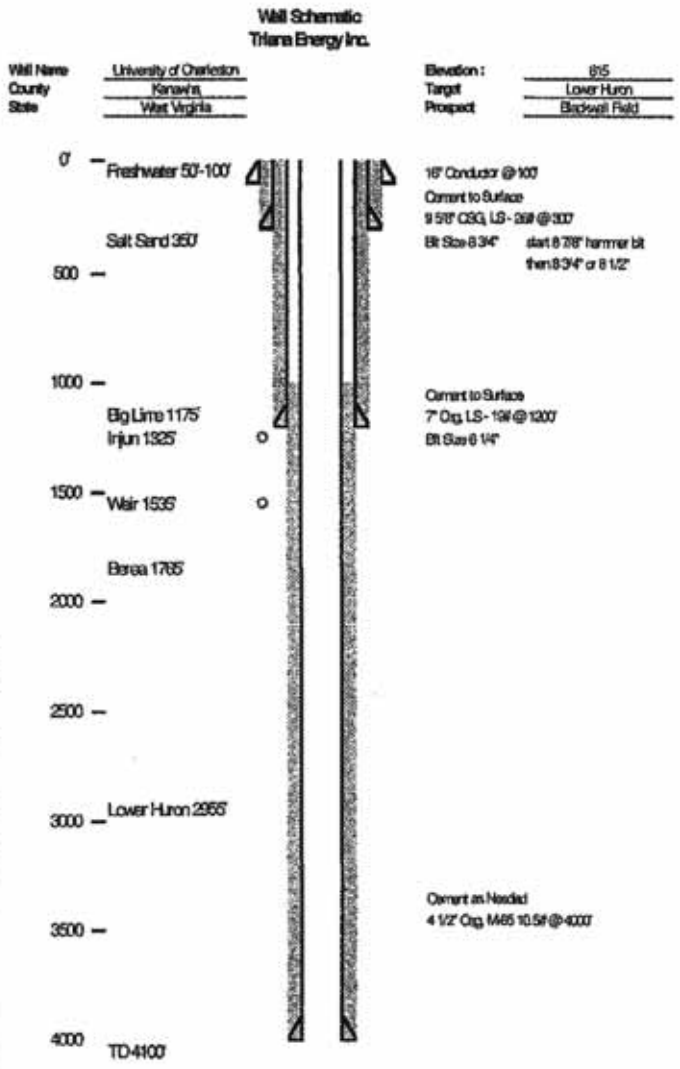


Figure #9 Arial photo of tbe rig drilling 12 3/8" hole. Note the adjacent parking lot and walkway connecting the parking lot to the white viewing tent next to location



Photo: John Sibold / Bryan Boyd Creative Group

Figure #10 Planned Well Schematic for the UC #1 well.



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(Cont.)

Figure #11 As seen from the rig floor, from left to right: the rig air compressors, steel pit and lid system, mud pump, and Kanawha River.



Figure #12 Nitrogen Fracturing Operations.



Figure #13 Nitrogen Fracturing Operations, view of the wellhead and office building in the background.



Figure #14 Removal of the location stone back to the river bank for crane removal and transport via barge.



Photo: Eddy Grey

Figure #15 Reclaimed path of tie-in from facility/meter to distribution pipeline.



Figure #16 Reseeding around wellhead upon project completion.



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Figure #17 Before, During and Ater views of the Blackwell Field project with the West Virginia State Capitol in the background.

BEFORE
(January)



DURING
(March)

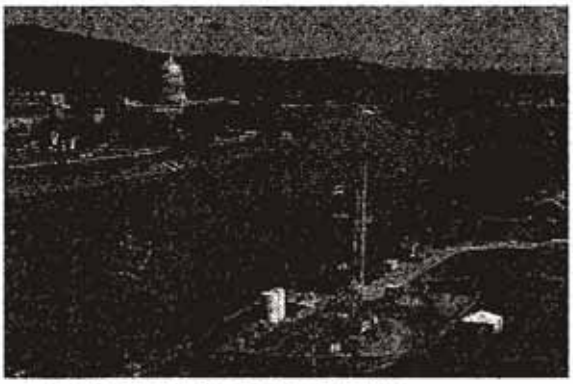


Photo: John Sibold / Bryan Boyd Creative Group

AFTER
(August)



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APPENDIX 10

pmk CONSULTANTS
ACOUSTICS | AUDIO | VISUAL SYSTEMS

ACOUSTICAL REPORT

Project: Barnett Shale Compressor Station

Re: Summary Acoustical Report

By: Ted N. Carnes – PMK Consultants – Dallas

Date: March 28, 2008

Introduction

An acoustical review was performed of a confidential Compressor Station in the Barnett Shale play in north-central Texas. The purpose of the study was to determine typical sound levels of the equipment both at the station yard and also an estimate of expected sound levels at nearby residential sites. The results of the latest study are summarized below.

In September of 2007, a site visit was made to the station to help determine the layout of the Sound Fighter Systems LSE Noise Barrier Wall around the two installed but not-operating compressor units. At that time it appeared that a sound wall would be needed on all four sides. There was concern about allowing adequate access for both occasional service vehicles and airflow to the relatively large but typically used coolers. As a result, large openings were placed on the west end of the south wall and the west end of the north wall. Some concern was expressed that while in general major sound reduction would be expected more sound maybe emitted from those two opening locations toward houses to the southwest and northwest than desired.

Just after startup and the installation of the LSE absorptive sound barrier walls, it was found that indeed more sound than desired was being emitted through the two openings. As a result, modifications to the fourth (detached) LSE sound barrier wall have been installed at the station. The placement of two additional "wing" walls on each end have provided greater sound reduction and at the same time allow plenty of room for cooling airflow and access. The design and installation have turned out well.

Sound Survey Results

A site visit was made to the station on the morning of Thursday January 24, 2008. Sound level measures were performed and physical observation made. The station has two cooler/engine/compressor units. Both of the units are CAT 3516 engine driven Ariel compressors, which were operating at round 1,250 rpm during the sound survey. While this version of compressor unit will operate at up to 1,400 rpm, operating at a nominal speed of 1,250 rpm would probably be more typical.

It is noted that the two CAT 3516 units have what appear to be perhaps only slightly better than regular grade mufflers installed. The use of more critical-grade mufflers is probably desirable, especially with the exhaust pipe stacks being so tall. Also these stacks have rain caps on them, which is not unusual but probably not typical. Gas flow

1420 W. Mockingbird Lane, Suite 400 ♦ Dallas, Texas 75247
(214) 688-7444 ♦ FAX (214) 951-7408

around the caps does produce sound that is somewhat noticeable outside the sound walls.

Typical overall A-weighted (dBA) and 1/3 octave band (dB) sound levels were obtained. The sound levels observed at the station yard by us and also at the nearby residences by others are provided below. Also see the attached Appendix, which also provide octave band sound levels.

Location	Overall Sound Levels, dBA	Remarks
At Station Yard -- Center Yard	92	
At West Fence	60	50' outside wall
Northwest Corner Yard	60	Contributions from other sound sources including traffic
Southwest Corner Yard	58	
South Fence Line	57	130' outside wall
First House to SW	53	Contribution from other sound sources in area
South and Southwest Residences	Less than 49	Other sound sources noticed more than from station

The closest house to the southwest has been the location of the greatest concern. The contribution from just the station would be estimated to be at no more than 50 dBA. It should be well below that value at all other residences in the area. It would appear that sound levels should be generally acceptable especially with all the traffic on I-20 that will occur day and night. While not necessarily used for this station for design, we typically suggest a limit of around 48 dBA at the closest houses for this type of situation. It would appear that this goal is being reasonably met. Also, the frequently-cited objective of achieving noise levels below 55 dBA at 300' also appears to be met. The exhausts are really the only sound source perhaps still of note.

No sound data were available without the sound barrier walls for before and after values to help determine the insertion loss. We have estimated up to 17 to 20 dBA of reduction at grade level with the walls around the compressors based measured sound data with the sound barrier in place. Thus the sound barrier wall is providing around 18 dBA of sound reduction, which is really quite good with the 20' barrier height.

Summary Comments

The new four sided sound barrier is providing good sound reduction. The use of the highly acoustical absorptive LSE panel is of an advantage at a station where the units must be enclosed and allowance must be made for access and cooling airflow. The sound barrier walls are performing comparably to all sides being completely enclosed.

This is a very successful installation of the LSE system.

Please let us know how we may be of further assistance. Thank you.

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(Cont.)

Appendix

Sound Level Inside and Outside 20' Tall Sound Fighter Systems LSE Sound Wall
Two CAT 3516 Engines/ Ariel Compressor/Single Fan Cooler Units.
Measured January 24, 2008

Location/ Condition	Sound Level, dB, at Octave Band Center Freq., Hz								Overall
	63	125	250	500	1,000	2,000	4,000	8,000	dBA
Inside Barrier - Center Yard	94	87	88	90	86	84	82	76	92
Center West Wall	92	82	81	80	77	73	70	65	82
Outside Barrier – Center West at 3'	80	75	66	57	54	47	40	32	63
Center West at 50'	75	68	62	55	56	49	42	36	60

Note: The 125 Hz sound is louder than might be expected at 50' due to tall exhaust outlet on mufflers and 125 Hz being the firing rate of engines.

APPENDIX 11

NOISE LEVEL MEASUREMENTS SOUND FIGHTER BARRIER WALL BAE SYSTEMS, INC. FACILITY YORK, PENNSYLVANIA

DRAFT REPORT DATED APRIL 7, 2009

PREPARED BY STEPHEN I. ROTH, PE
ROTH ACOUSTICAL ASSOCIATES, LLC

On April 2, 2009, noise level measurements were taken to determine the noise reductions provided by a Sound Fighter LSE barrier wall. The wall was erected to reduce noise transmission of Fighting Vehicles (tanks) to the community. The tanks are operated on a test track in the vicinity of homes.

The measurements were taken at a BAE Systems, Inc. facility in York, Pennsylvania. Measurements were taken in a grass field adjacent to the test track.

Matt Harding (Sound Fighter Systems, LLC) and Scott Wilkinson (BAE Systems, Inc) accompanied me during the measurements.

All measurements were collected with a Rion NA-27 Type 1 Integrating Noise Analyzer. It was last laboratory calibrated on May 9, 2008. The Calibration Certificate is enclosed with this report. The meter was field calibrated before and after the measurements and found to be accurate and in working order.

Detailed one third octave band noise level information on the measurements is documented on the attached Noise Level Data Sheets. Measurement locations, A-Weighted noise levels and a Summary of the noise reductions are shown on Page 3 of this report. All measurements were taken with the meter set on "fast" response.

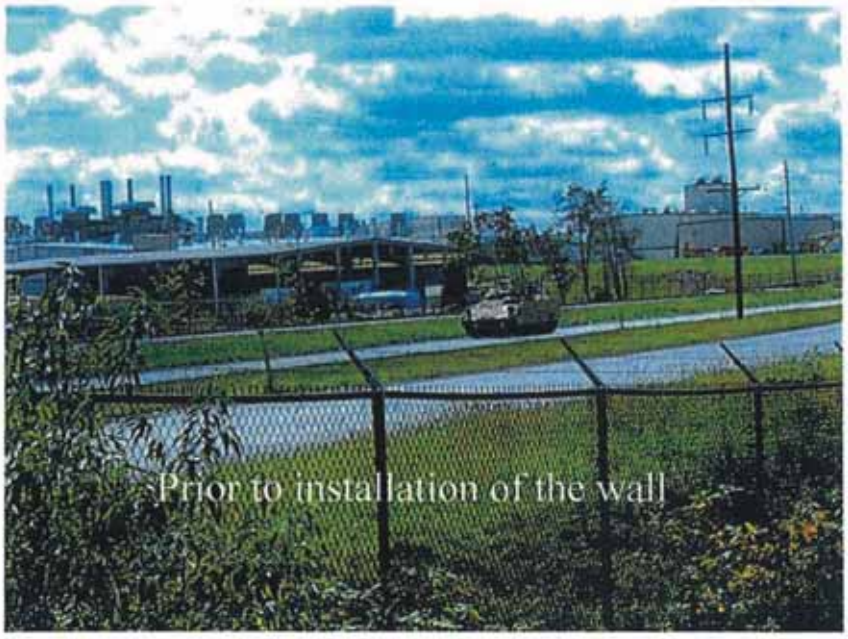
It was a partly cloudy day. Wind was calm. Temperature was 65°F.

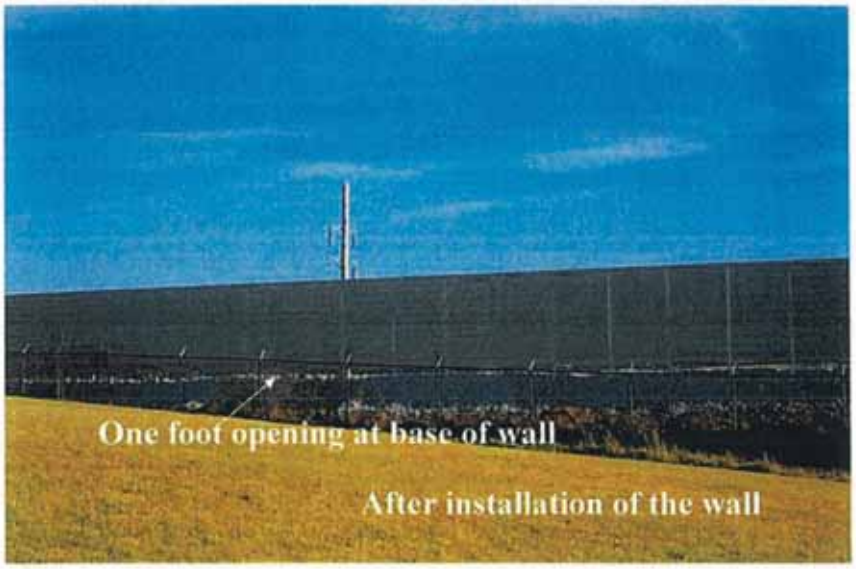
Pictures on Page 2 show the test track before installation of the barrier wall and with the barrier wall in place. The wall is ten feet high with a one foot opening at its bottom. The one foot opening, compromising the noise reduction ability of the wall, has been created by the settling of gravel at the base of the wall. The wall is 300 feet long.

Roth Acoustical Associates, LLC
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Noise level measurements
Sound Fighter Wall Installation – York, PA
Draft Report dated April 7, 2009



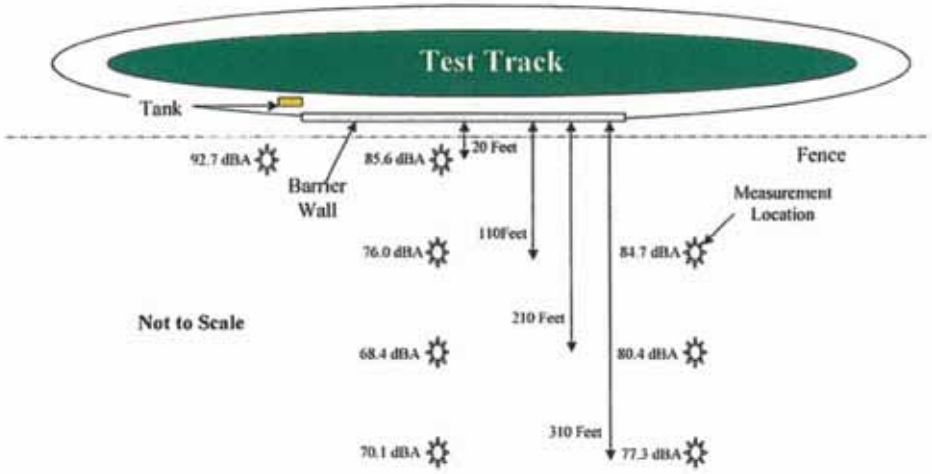


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Noise level measurements
Sound Fighter Wall Installation – York, PA
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Measurement Locations and A-Weighted Noise Levels



Measured by Stephen I. Roth, PE – April 2, 2009 – BAE Tank Test Track- York, PA

SUMMARY - MEASURED NOISE REDUCTIONS

	Octave Band Center Frequency						
	125 Hz	250 Hz	500 Hz	1000 Hz	2000 Hz	4000 Hz	dBA
20 feet from the Sound Fighter wall	2.0 dB	5.5	7.5	9.7	8.0	5.3	7.1
110 feet from the Sound Fighter wall	3.3	5.0	12.5	7.0	4.2	6.7	8.7
210 feet from the Sound Fighter wall	7.4	5.0	16.4	8.0	12.0	12.3	12.0
310 feet from the Sound Fighter wall	7.8	1.4	11.9	6.8	4.2	4.2	7.2

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Scantek, Inc.
CALIBRATION LABORATORY

ISO 17025: 2005, ANSI/NCSL Z540:1994 Part I and relevant requirements of ISO 9002:1994 ACCREDITED by NVLAP (an ILAC and APLAC signatory)

NVLAP®

NVLAP Lab Code: 200625-0

Calibration Certificate No.17849

Instrument:	**Sound Level Meter**	*Date Calibrated:*	**5/9/2008**
Model:	**NA27**	*Status*	
Manufacturer:	**Rion**	*In tolerance*	
Serial number:	**01070552**	*Out of tolerance*	
Tested with:	**Microphone UC53 s/n 76461**	*See comments*	
	Preamplifier NH20 s/n 73507	*Contains non-accredited tests:*	__Yes X No
Type (class):	**1**	*Calibration service:*	__ Basic X Standard
Customer:	**Roth Acoustical Associates**	*Address:*	**2352 Norton Road**
Tel/Fax:	**412-831-8382/ -8389/**		**Pittsburgh, PA 15241**
	sroth@rothacoustics.com		

Tested in accordance with the following procedures and standards:
Calibration of Sound Level Meters, Scantek Inc., 08/07/2005
SLM & Dosimeters – Acoustical Tests, Scantek Inc., 06/15/2005

Instrumentation used for calibration: Nor-1504 Norsonic Test System:

Instrument - Manufacturer	Description	S/N	Cal date	Traceability evidence Cal. Lab / Accreditation
4838-Norsonic	SME Cal Unit	25747	Jan 15, 2008	Scantek, Inc./NVLAP
DS-360-SRS	Function Generator	61646	Nov 19, 2007	Davis Inotek / AClass
34401A-Agilent Technologies	Digital Voltmeter	MY41022043	Nov 13, 2007	Transcat / NVLAP
DPI 141-Druck	Pressure Indicator	790/00	Nov 9, 2006	Transcat / A2LA
HM30-Thommen	Meteo Station	1040170/39633	Dec 21, 2007	Transcat / A2LA
PC Program 1019 Norsonic	Calibration software	v:46	Validated Dec 2006	-
1253-Norsonic	Calibrator	25726	Jan 29, 2008	Scantek, Inc./NVLAP

Instrumentation and test results are traceable to SI (International System of Units) through standards maintained by NIST (USA) and NPL (UK).

Environmental conditions:

Temperature (°C)	Barometric pressure (kPa)	Relative Humidity (%)
23.8 °C	98.881 kPa	48.1 %RH

Calibrated by	Valentin Buzduga	Checked by	Mariana Buzduga
Signature		Signature	
Date	5/09/2008	Date	5/12/2008

Calibration Certificates or Test Reports shall not be reproduced, except in full, without written approval of the laboratory.
This Calibration Certificate or Test Reports shall not be used to claim product certification, approval or endorsement by NVLAP, NIST, or any agency of the federal government.
Document stored as: C:\Nor1504\SlmCal\2008\RIONA27_01070552_M1.doc

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Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Noise level measurements - Sound Fighter Sound Wall
Measured at BAE Systems, Inc. , York, PA
Measured on April 2, 2009
Measured by Stephen I. Roth, PE - Accompanied by Matt Harding (Sound Fighter) and Scott Wilkinson (BAE)
Instrument: Rion NA-27 Type 1 Noise Analyzer
Laboratory calibrated on May 8, 2008
Field calibrated before and after the measurements
Partly cloudy - Wind calm - 65°F

Lmax	Maximum noise level during measurement period
Leq	Average noise level during measurement period
L90	Ambient background noise level

Measurement Number: 1
Background ambient noise level
Date of measurement: 04-02-2009
Time of measurement: 13:47:45
Measurement Period: 00:00:10:41

			One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
L90	53.4	54.7	61.6	52.1	40.9	38.5	36.9	36.8	41.4	42.4	44.4	46.0	43.0	40.1	36.1	33.1	31.7	27.0	21.5

Measurement Number: 2
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 20 feet from the barrier wall
Time of measurement: 13:52:35
Measurement Period: 00:00:11:51

			One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	92.8	92.5	87.8	91.4	85.3	83.7	86.3	86.9	83.9	84.1	85.3	80.0	84.1	83.2	83.2	79.8	77.8	77.1	75.2
Leq	86.2	82.5	79.7	83.6	77.5	75.1	75.7	77.2	75.7	75.7	77.7	71.9	75.8	74.6	74.2	71.0	69.2	69.1	66.4

Measurement Number: 3
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 20 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 13:50:52
Measurement Period: 00:00:10:39

			One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	92.6	94.3	87.8	89.8	85.3	81.9	86.7	85.8	85.2	83.1	87.9	79.8	84.1	82.2	83.9	79.4	77.5	77.8	74.1
Leq	85.3	83.9	80.6	82.0	77.8	74.3	76.4	77.4	76.4	76.2	77.5	72.8	76.2	74.5	74.4	71.3	69.3	68.6	65.9

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Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Measurement Number: 4
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 20 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 13:53:21
Measurement Period: 00:00:10:88

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	89.7	85.1	99.3	94.5	83.5	83.7	83.1	84.5	83.6	80.0	80.3	77.1	78.6	78.5	74.0	74.0	70.5	73.6	70.0
Leq	82.0	77.6	91.6	86.9	75.6	75.7	73.6	76.0	75.8	73.2	72.6	69.8	69.9	68.8	67.2	66.6	63.8	65.0	61.7

Measurement Number: 5
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 20 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 13:54:19
Measurement Period: 00:00:07:28

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	94.3	94.0	87.3	92.4	86.2	83.4	86.6	86.7	84.1	84.7	90.3	81.2	84.1	88.5	86.4	81.2	78.6	78.5	75.6
Leq	88.4	84.3	80.6	84.5	79.4	75.7	78.0	78.8	77.5	77.9	83.1	74.3	77.5	80.1	77.2	74.0	72.0	71.5	68.9

Measurement Number: 6
Measured as tank passed by - Measured in front of the barrier wall
Measured at 20 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 13:55:41
Measurement Period: 00:00:10:58

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	83.9	79.8	96.5	89.4	77.6	74.9	73.9	77.6	77.7	71.4	71.2	67.1	66.2	64.8	65.1	67.6	62.6	63.3	59.5
Leq	77.0	74.5	89.2	81.6	69.8	69.1	66.9	69.3	69.3	64.9	64.2	60.1	60.1	59.2	58.9	58.9	56.6	57.1	53.8

Measurement Number: 7
Measured as tank passed by - Measured in front of the barrier wall
Measured at 20 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 13:56:04
Measurement Period: 00:00:09:58

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	86.4	93.8	85.7	88.7	84.4	73.6	75.9	77.4	78.4	74.3	78.3	71.2	76.3	78.0	75.9	74.4	73.6	72.8	70.8
Leq	78.1	83.3	77.9	81.1	75.2	67.3	66.3	69.2	69.1	67.4	71.0	64.6	67.8	68.8	67.4	65.6	65.0	64.4	62.5

Measured by Stephen I. Roth, PE

Measured on April 2, 2009

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(Cont.)

Noise level measurements
Sound Fighter Wall Installation – York, PA
Draft Report dated April 7, 2009

COMMENTARY

To determine the noise reductions provided by a Sound Fighter LSE Sound Wall, noise levels were measured at a BAE Systems, Inc. tank test track in York, PA. The Sound Fighter wall was 10 feet high and 300 feet long. It had a 1 foot opening at its base created by the settling of gravel.

Measurements were taken at locations in front of the wall and also at locations on the side of the wall (to simulate the condition without a wall present. Three or more measurements were taken at each location (when possible) to use averages for noise reduction calculations.

As a tank passed behind the wall, the noise reductions provided by the wall were very obvious at all locations in front of the wall.

All measurements were taken when the tank was traveling on the inside track, closer to the sound wall.

Noise reductions were 7.1 – 12.0 dBA depending on measurement locations. These reductions were calculated by comparing the measurements at comparable distances, with and without the wall affecting the measurements.

The noise reduction capability was compromised by the one foot opening at the base of the sound wall.

Respectfully,

Stephen I. Roth

Stephen I. Roth, PE, FASA
Board Certified – Institute of Noise Control Engineering

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(Cont.)

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Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Measurement Number: 8
Measured as tank passed by - Measured in front of the barrier wall
Measured at 20 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 13:57:47
Measurement Period: 00:00:08:36

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	86	92.2	85.2	86.3	84.4	72.9	76.7	76.6	79.3	74.4	77.7	71.4	76.7	76.3	76.1	73.8	73.5	73	70.3
Leq	79.5	83.5	77.8	81	75.9	67.4	69.3	70.6	70.3	67.8	70.6	66	68.2	70.3	68	66.3	65.3	64.7	62.8

Measurement Number: 9
Measured as tank passed by - Measured in front of the barrier wall
Measured at 20 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:01:32
Measurement Period: 00:00:10:21

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	81.2	86.7	86.1	82.7	75.7	73.7	74.4	75.0	79.6	75.1	74.1	72.7	69.2	69.9	68.7	66.0	60.9	62.2	60.3
Leq	74.2	78.0	77.7	72.8	68.2	65.1	65.9	66.5	69.3	66.7	64.2	63.3	61.9	62.9	60.7	57.9	55.1	55.9	53.7

Measurement Number: 10
Measured as tank passed by - Measured in front of the barrier wall
Measured at 110 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:03:19
Measurement Period: 00:00:08:72

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	73.1	80.8	82.4	77.0	69.0	67.2	60.0	68.4	66.0	64.5	64.4	65.5	63.0	61.9	61.5	57.5	58.2	62.5	58.0
Leq	69.4	75.2	75.9	70.8	64.7	60.1	58.0	61.0	62.2	60.3	58.4	59.0	56.6	57.5	56.3	52.8	51.3	54.4	51.2

Measurement Number: 11
Measured as tank passed by - Measured in front of the barrier wall
Measured at 110 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:05:05
Measurement Period: 00:00:07:43

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	72.6	77.7	82.5	77.6	70.0	68.0	60.9	67.3	65.1	64.6	64.1	64.0	61.5	63.1	61.6	57.3	58.3	60.7	57.3
Leq	69.2	73.0	76.7	70.1	64.7	60.7	57.4	61.5	61.8	60.4	58.6	58.0	55.9	57.8	56.0	52.5	51.0	54.3	51.1

Measured by Stephen I. Roth, PE

Measured on April 2, 2009

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(Cont.)

Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Measurement Number: 12
Measured as tank passed by - Measured in front of the barrier wall
Measured at 110 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:08:30
Measurement Period: 00:00:05:81

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	73.8	77.1	80.2	76.0	68.7	66.3	62.0	67.9	66.0	67.3	65.4	66.6	63.5	63.0	62.5	59.6	57.2	61.6	59.2
Leq	70.3	73.6	76.6	70.5	63.8	59.6	57.4	62.2	63.2	61.5	60.3	60.6	57.6	56.8	56.8	54.3	52.3	56.4	54.3

Measurement Number: 13
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 110 feet from the barrier wall
This measurement was influenced by a mound between the microphone and the tank providing lower measured noise levels
This measurement was not included in calculations
Date of measurement: 04-02-2009
Time of measurement: 14:10:12
Measurement Period: 00:00:08.73

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	78.0	87.4	88.8	81.4	76.4	72.8	73.5	73.3	68.3	68.3	67.0	64.4	65.0	66.6	66.1	63.2	62.9	62.2	60.1
Leq	72.4	81.1	81.7	73.3	70.8	67.5	65.1	66.4	62.8	63.7	60.1	58.4	58.3	59.2	57.8	54.8	53.8	54.7	52.6

Measurement Number: 14
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 110 feet from the barrier wall
This measurement was influenced by a mound between the microphone and the tank providing lower measured noise levels
This measurement was not included in calculations
Date of measurement: 04-02-2009
Time of measurement: 14:11:52
Measurement Period: 00:00:08.95

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	76.8	85.8	87.6	81.1	75.1	74.1	71.8	69.7	66.1	65.8	67.0	64.8	64.5	67.0	65.3	62.9	62.1	62.6	60.1
Leq	72.4	77.8	80.7	73.1	70.0	67.6	64.6	64.6	62.3	62.0	62.4	60.3	59.6	60.5	58.9	56.4	54.8	56.1	54.3

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(Cont.)

Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Measurement Number: 15
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 110 feet from the barrier wall
This measurement was influenced by a mound between the microphone and the tank providing lower measured noise levels
This measurement was not included in calculations
Date of measurement: 04-02-2009
Time of measurement: 14:13:38
Measurement Period: 00:00:06:06

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	73.9	86.9	91.9	81.4	74.7	73.6	75.4	71.7	69.3	65.4	68.3	65.2	64.2	65.7	64.2	62.3	60.9	62.5	61.1
Leq	72.6	79.5	82.3	73.8	70.7	68.4	65.8	65.5	62.6	60.6	62.2	58.9	58.8	59.5	57.9	55.0	54.2	55.8	53.7

Measurement Number: 16
Measured as tank passed by - Measured in front of the barrier wall
Measured at 210 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:15:15
Measurement Period: 00:00:08:57

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	66.8	78.1	80.0	71.0	65.0	62.2	59.8	62.0	61.6	60.2	62.4	61.9	58.4	60.2	57.8	54.4	51.4	54.0	51.8
Leq	65.4	73.7	76.1	65.4	60.2	56.3	49.0	53.6	54.9	53.6	55.4	54.4	52.1	53.3	51.0	48.2	46.0	48.2	45.5

Measurement Number: 17
Measured as tank passed by - Measured in front of the barrier wall
Measured at 210 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:16:57
Measurement Period: 00:00:06:46

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	68.7	73.7	77.8	70.5	63.0	60.4	52.6	59.5	61.0	59.3	63.9	61.5	56.2	57.1	56.3	53.6	50.3	52.7	49.9
Leq	64.8	70.2	74.0	65.1	58.2	52.7	46.9	53.5	56.1	54.2	56.5	54.6	52.3	53.2	51.4	48.4	45.8	48.0	44.7

Measurement Number: 18
Measured as tank passed by - Measured in front of the barrier wall
Measured at 210 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:18:38
Measurement Period: 00:00:09:46

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	67.5	76.2	75.7	70.2	65.4	63.4	54.1	57.3	60.5	58.9	61.9	58.3	56.8	58.4	56.5	53.4	52.3	53.6	52.0
Leq	63.6	70.0	71.7	64.8	60.1	56.7	49.7	51.5	54.6	52.9	54.3	52.4	51.1	52.6	50.6	47.1	44.5	46.6	44.4

Measured by Stephen I. Roth, PE

Measured on April 2, 2009

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(Cont.)

Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Measurement Number: 19
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 210 feet from the barrier wall
This measurement was influenced by a mound between the microphone and the tank providing lower measured noise levels
This measurement was not included in calculations
Date of measurement: 04-02-2009
Time of measurement: 14:20:24
Measurement Period: 00:00:08:81

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	70.6	82.9	82.3	76.8	73.4	68.1	69.7	67.4	66.1	62.4	62.3	61.3	60.8	63.0	58.4	56.0	51.7	51.4	48.4
Leq	68.2	75.1	77.0	70.2	67.4	63.6	61.9	61.8	60.3	56.9	56.9	55.1	54.7	56.2	52.2	50.1	46.8	47.2	45.1

Measurement Number: 20
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 210 feet from the barrier wall
This measurement was influenced by a mound between the microphone and the tank providing lower measured noise levels
This measurement was not included in calculations
Date of measurement: 04-02-2009
Time of measurement: 14:21:40
Measurement Period: 00:00:06:81

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	71.1	82.1	79.9	75.4	72.3	70.1	66.1	66.6	66.2	60.3	55.8	53.6	55.7	55.1	54.8	53.2	51.0	50.5	49.5
Leq	67.1	76.0	74.0	69.9	66.2	62.7	60.5	63.6	61.0	55.1	50.4	51.4	52.0	52.0	51.5	50.0	47.6	47.0	44.7

Measurement Number: 21
Measured as tank passed by - Measured to the left of the barrier wall
Measured at 210 feet from the barrier wall
This measurement was influenced by a mound between the microphone and the tank providing lower measured noise levels
This measurement was not included in calculations
Date of measurement: 04-02-2009
Time of measurement: 14:23:15
Measurement Period: 00:00:08:27

		One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	70.0	81.4	81.7	75.3	71.4	67.1	66.5	70.6	65.7	57.5	57.8	59.7	61.4	60.9	59.8	55.5	52.5	51.8	49.6
Leq	67.1	72.4	75.9	69.1	65.6	61.9	59.8	65.9	59.3	53.2	51.9	52.9	54.1	53.4	52.7	50.6	48.3	47.3	44.8

Measured by Stephen I. Roth, PE

Measured on April 2, 2009

D2-256
(Cont.)

Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Measurement Number: 22
Measured as tank passed by - Measured in front of the barrier wall
Measured at 310 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:24:53
Measurement Period: 00:00:07:59

			One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	67.0	72.4	74.2	68.8	67.5	58.1	51.5	56.3	55.6	54.8	54.7	56.9	57.3	57.9	57.3	57.3	54.9	55.2	51.6
Leq	61.7	69.6	68.2	62.0	60.1	52.4	46.5	51.1	50.6	49.4	48.8	50.2	50.9	51.3	50.3	49.4	47.8	47.2	44.0

Measurement Number: 23
Measured as tank passed by - Measured in front of the barrier wall
Measured at 310 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:28:32
Measurement Period: 00:00:07:07

			One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	71.0	76.7	74.0	67.2	66.9	57.7	54.1	60.0	61.0	60.7	60.3	60.5	62.5	62.6	62.0	62.7	59.0	57.2	53.6
Leq	66.9	68.8	68.8	63.0	58.6	52.6	49.6	56.9	55.9	56.1	54.2	56.0	57.0	57.7	57.0	56.2	53.5	51.3	47.8

Measurement Number: 24
Measured as tank passed by - Measured in front of the barrier wall
Measured at 310 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:28:11
Measurement Period: 00:00:06:41

			One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	71.1	76.4	76.9	69.4	66.2	59.0	52.8	63.9	61.8	62.8	61.2	60.3	62.4	64.1	61.4	60.8	58.7	57.7	55.1
Leq	67.1	69.4	70.1	63.4	57.8	53.3	48.4	58.3	55.3	54.9	54.2	55.7	57.4	58.6	57.1	56.9	52.8	52.2	48.6

Measurement Number: 25
Measured as tank passed by - Measured to the right of the barrier wall
Measured at 310 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:53:14
Measurement Period: 00:00:07:33

			One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	78.6	80.9	85.8	74.5	63.4	62.1	66.5	70.9	74.6	70.9	68.9	67.5	68.5	66.2	67.2	64.9	62.1	62.5	59.0
Leq	73.0	74.0	78.4	67.8	60.1	58.2	60.0	66.6	69.2	65.9	62.4	62.0	62.0	60.4	59.8	58.7	56.5	55.4	52.5

Measured by Stephen I. Roth, PE

Measured on April 2, 2009

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Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Measurement Number: 26
Measured as tank passed by - Measured to the right of the barrier wall
Measured at 310 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:54:55
Measurement Period: 00:00:07:70

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	77.1	83.8	83.2	75.5	62.1	62.3	64.0	71.2	73.4	68.3	66.9	67.2	66.0	63.3	58.3	55.8	52.8	51.5	50.7
Leq	72.9	77.9	77.2	68.5	58.5	55.6	59.6	65.2	68.3	63.8	61.3	62.7	61.9	60.5	59.5	58.3	56.0	56.1	53.2

Measurement Number: 27
Measured as tank passed by - Measured to the right of the barrier wall
Measured at 310 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:56:35
Measurement Period: 00:00:08:50

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	75.7	82.2	82.4	71.9	60.3	62.3	67.0	74.1	72.8	69.1	65.1	64.8	65.2	65.3	62.0	61.1	60.2	58.5	55.3
Leq	71.1	74.8	74.8	66.2	56.7	58.2	60.3	65.4	67.0	62.2	59.9	58.8	59.7	59.7	58.5	55.8	54.8	53.4	49.6

Measurement Number: 28
Measured as tank passed by - Measured to the right of the barrier wall
Measured at 210 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:58:15
Measurement Period: 00:00:08:05

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	79.2	85.3	78.2	77.4	66.3	68.3	67.8	74.2	78.3	71.3	69.2	68.1	67.8	68.4	66.5	66.2	66.0	65.0	62.1
Leq	74.5	77.8	72.2	70.8	61.0	53.6	61.7	68.8	71.9	66.4	64.0	61.8	62.0	63.0	60.9	60.4	58.9	57.6	53.8

Measurement Number: 29
Measured as tank passed by - Measured to the right of the barrier wall
Measured at 210 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 14:59:57
Measurement Period: 00:00:07:95

		One-third octave band center frequency (Hz)																	
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	81.0	83.7	78.9	81.4	68.8	60.7	66.7	73.8	80.4	76.1	67.6	69.1	68.2	70.9	65.8	66.9	65.0	63.2	59.7
Leq	76.0	76.0	73.1	73.0	63.4	55.5	60.5	67.5	75.4	70.4	63.3	62.8	63.5	64.6	62.3	61.5	59.9	58.1	54.7

Measured by Stephen I. Roth, PE

Measured on April 2, 2009

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(Cont.)

Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Measurement Number: 30
Measured as tank passed by - Measured to the right of the barrier wall
Measured at 210 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 15:01:35
Measurement Period: 00:00:08.08

			One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	80.8	85.7	87.7	80.9	79.8	80.0	87.5	76.2	78.6	73.3	70.4	68.6	68.5	72.3	69.7	69.5	63.7	68.2	67.3
Leq	76.1	78.8	80.5	72.7	64.4	65.1	61.6	69.1	72.9	68.1	65.4	63.3	63.2	64.7	62.9	62.3	59.0	59.5	55.6

Measurement Number: 31
Measured as tank passed by - Measured to the right of the barrier wall
Measured at 110 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 15:08:04
Measurement Period: 00:00:08.28

			One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	84.6	89.4	84.3	87.4	78.9	71.2	78.2	82.9	84.3	76.5	72.2	70.7	68.4	99.6	68.1	66.0	65.3	67.4	62.9
Leq	78.1	81.6	79.5	82.4	73.1	64.4	71.0	76.2	77.0	69.9	66.2	64.9	63.5	93.3	63.4	61.5	60.4	61.1	56.7

Measurement Number: 32
Measured as tank passed by - Measured to the right of the barrier wall
Measured at 110 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 15:10:07
Measurement Period: 00:00:08.90

			One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	84.9	91.5	83.1	86.8	77.5	73.0	80.2	84.1	84.3	73.7	74.6	72.3	68.3	87.7	87.5	66.3	66.0	66.5	63.1
Leq	78.0	83.8	78.3	81.5	72.0	64.6	71.9	76.8	76.7	69.3	67.7	65.5	63.3	63.1	62.7	61.0	60.7	60.6	56.6

Measurement Number: 33
Measured as tank passed by - Measured to the right of the barrier wall
Measured at 110 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 15:11:53
Measurement Period: 00:00:09.24

			One-third octave band center frequency (Hz)																
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	84.7	93.7	83.4	85.9	77.2	72.1	81.4	84.5	83.2	75.7	72.1	70.3	70.7	88.2	88.7	66.8	65.3	64.7	61.2
Leq	78.6	85.6	78.8	80.6	71.9	64.5	71.6	76.6	75.6	69.5	66.3	64.6	64.6	63.5	63.2	61.8	60.4	59.9	56.3

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(Cont.)

Noise Level Measurements - Sound Fighter Wall System
BAE Systems, Inc. York, PA

Measurement Number: 34
Measured as tank passed by - Measured in front of the barrier wall
Measured at 110 feet from the barrier wall
Date of measurement: 04-02-2009
Time of measurement: 15:15:48
Measurement Period: 00:00:03:40

									One-third octave band center frequency (Hz)											
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	76.0	89.7	80.6	82.9	77.4	59.0	63.9	59.9	72.1	65.8	65.6	64.0	63.6	63.8	64.1	62.6	59.3	59.1	55.7
Leq	73.3	80.4	76.1	79.7	73.6	55.3	57.0	63.7	65.5	60.0	62.4	60.0	60.7	60.6	60.8	59.0	56.6	56.0	52.5

Measurement Number: 35
Measured as tank passed by
Measured at fitness center (gym)
Date of measurement: 04-02-2009
Time of measurement: 15:28:08
Measurement Period: 00:00:12:88

									One-third octave band center frequency (Hz)											
Data type	dBA	100 Hz	125 Hz	160 Hz	200 Hz	250 Hz	315 Hz	400 Hz	500 Hz	630 Hz	800 Hz	1 kHz	1.25 kHz	1.6 kHz	2 kHz	2.5 kHz	3.15 kHz	4 kHz	5 kHz
Weighting	A	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat	Flat
Lmax	89.7	98.1	87.5	90.8	87.8	78.3	80.7	85.0	85.3	83.3	81.7	79.6	78.8	78.4	76.5	77.3	73.2	78.7	76.3
Leq	53.8	87.7	79.8	80.5	79.0	72.1	72.7	77.3	77.5	76.1	75.6	72.5	71.3	71.4	70.5	69.3	66.8	66.0	66.8

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(Cont.)

APPENDIX 12

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

DIRECT TESTIMONY OF

JIM FOSSUM

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

D2-257

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail: ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: September 5, 2008

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A. SMUD Request for Proposal No. 91-2

B. Sacramento City Council Resolution No. 2007-62:3

C. James R. Shetler (SMUD) February 25, 2008 Letter to Commissioner Simon and Administrative Law Judge Richard Smith

D. Map of Reservoir Surface Area

E. Aerial Map of Project Components

F. New Well Graphics

G. Rendering of New Well Site

H. Land Use Chart

I. Form of Underground Gas Storage Lease

J. Outline of Community Foundation

K. Project Labor Agreement

D2-257 (Cont.)

I. PROFESSIONAL BACKGROUND

Q1 ***Please State Your Name, Business Address, and Present Occupation.***

My name is Jim Fossum. My business address is 8031 Fruitridge Road #B, Sacramento, CA 95820. I am the Chairman of Sacramento Natural Gas Storage, LLC.

Q2 ***Please Provide A Brief Description Of Your Background.***

I grew up in a small town in Minnesota in the 30's and 40's. After a brief tour in the U.S. Army in the late 40's I attended St. Olaf College, graduating in 1954. Thereafter, I spent a few years working with delinquent boys and then the Chippewa Indians in northern Minnesota. I subsequently attended graduate school in Nebraska receiving a Masters Degree in Social Work in 1958. This was followed by 2 years working with mentally ill offenders and then as the Director of a mental health center in a rural Wisconsin community.

In 1962, I came to Atascadero, California as a Social Worker at the State Hospital for mentally ill offenders. Three years later, I was Chief of Social Service at that facility and in 1966 I moved to Sacramento as the Assistant Chief of Social Services for the 13 State Hospitals. This was followed by a stint as the Assistant to the Director of the State Hospitals and then 2 years as the Chief of aftercare services for the Mental Health System. In this capacity, I managed 51 offices throughout the state with a staff of about 1,200 persons.

Then, I was appointed to be the Executive Assistant to the Director of Health in a Department that encompassed Mental Health, Public Health, Social Welfare, Employment, and Vocational Rehabilitation. After a change of Administration, I became the Executive Director of the Sonoma State Hospital.

Q3 ***Provide A Brief Description of Your Early Experience In Natural Gas.***

In 1986 I changed careers after the deregulation of natural gas by the FERC on the interstate pipeline system. I established a California natural gas marketing company for a Houston-based gas marketing company. This developed into a large firm that was moving approximately one half billion cubic feet of gas a day to California and other Western states from the southwest, Rockies, Canada, as well as California production. Customers included the three major California gas utilities, large industrial customers, and small industrial customers.

Q4 ***Provide A Brief Description of Your Experience With Petrodata.***

In 1992, I formed Petrodata, a database firm that assembled all of the data on California oil and gas wells and fields. The database provided production data, well histories, and well logs from 1914 to the present, and was utilized by various firms for planning drilling programs, reviewing production data for investors, geologists and reservoir engineers and others requiring information on wells and fields. Initial partners in this enterprise

D2-257 (Cont.)

included John Matthews[1] as a full partner and Don Russell as an investor. I sold Petrodata in 2003, but retained information from the database.

Q5 ***Provide A Brief Description of Your Experience With Lodi.***

In about May 1992, SMUD put out an RFP for the development of natural gas storage capacity. Together with John Matthews, I reviewed various fields in the Sacramento Basin to determine fields that were suitable for development into natural gas storage projects. We determined criteria for initial field screening. These included:

- Size of field
- Location in relation to pipelines
- Geology/Reservoir Engineering
- Seismic Issues
- Environmental Issues
- Potential Cost

This process resulted in our selection of the Lodi project as a potential candidate for the SMUD criteria. However, SMUD did not make a selection at that time but has continued to seek on-system storage.

D2-257 (Cont.)

During the 90's, I developed the Lodi project and found funding. The firm that funded the project brought in a new management group, but I was retained as a Sr. Vice President throughout the project's development and construction. During construction, I was the on-site representative of the owner in the drilling and dehydration facets of the program.

My wife was diagnosed with Myeloma in about 2003, and I left the industry to be with her until she died in 2004.

Q6 ***What Is The Genesis Of The Florin Reservoir Project?***

In the fall of 2004, Don Russell and I decided to pursue the development of one or more gas storage projects at locations in California where a significant need exists. Our motivation was to make a contribution to the community in a collaborative endeavor. We were aware of the SMUD need and the fragile nature of the supply system in the Sacramento region. We had information on the gas reservoirs in the area, one of which (Florin) was ideal for the SMUD and greater Sacramento need. We formed Sacramento Natural Gas Storage, LLC, as a legal entity for the project development and operation.

[1] John Matthews is a Reservoir Engineer and independent Consultant, who has been employed in the California gas and oil industry for the over 50 years.

Q7 ***Who Are The Key Players In Sacramento Natural Gas Storage, LLC?***

The key players are: Don Russell, Wells Fargo Energy Capital[2] and I. The Board of Directors includes Don Russell (President), Michael Nepveux (Wells Fargo) and myself (Chairman). Tom Kalb from Westport Energy Capitol[3] is a non-voting member.

Q8 ***What Are The Roles Of Mr. Russell And Yourself?***

Being a very small development group, we are somewhat interchangeable. However, we have divided up principal responsibilities as follow:

- Don Russell – Engineering, Safety, Contracts, Financial, Leed Certification.
- Myself – Land Acquisition, Storage Sales, Community Relations.

II. NEED FOR PROJECT

Q9 ***What Is The Specific Purpose And Need For The Florin Project?***

The location of the Florin Field in the southern part of the city of Sacramento provides the highest direct value to major users of natural gas of any depleted natural gas reservoir in the Sacramento area. It also provides the highest indirect value to all of Sacramento's residents. Major users of natural gas include government entities, public utilities, private sector industries, and private enterprises engaged in the provision of natural gas to their end-user customers.

The current "anchor tenant" for the SNGS storage facility is the Sacramento Municipal Utility District ("SMUD"). The Florin Field is located within one-half mile of the SMUD pipeline system. This storage facility represents a capability that SMUD has been seeking since 1992.[4] The SNGS facility will provide true "on-system" storage to SMUD. The natural gas that SMUD will store in the SNGS facility will be delivered directly into their pipeline system serving all of their electric power generation plants. The SNGS facility will thus give SMUD the reliable storage it has been seeking since 1992.

The pipeline that will need to be constructed from the SMUD pipeline to the SNGS Compressor Station is less than 4,000 feet in length and is all located within the boundaries of the Depot Park, a City-zoned industrial development area. The choice of the Florin field also permits SNGS to locate its Compressor Station and Control Center on the old Sacramento Army Depot, thereby supporting the City's

D2-257 (Cont.)

[2] Wells Fargo Energy Capital is a subsidiary of Wells Fargo Bank; it is headquartered in Houston, and has a Western United States office in Denver.
[3] Westport Energy Capitol is a financial firm in Westport, Connecticut.
[4] *See* SMUD Request for Proposal No. 91-2, a copy of which is provided as **Exhibit A.**

redevelopment of the area as a "Green Tech Zone."[5] Because of its location, the project will also qualify as a "brownfield" development.

Q10 ***Please Describe The Interstate Pipeline Systems Service To The Sacramento Region.***

The Sacramento Metropolitan Area receives all of its supply of natural gas from connections to the PG&E Lines 400/401 "backbone" pipeline system that runs north and south through the center of the State. The vast majority of the natural gas that comes to Sacramento comes from western Canada, a trip of over 1000 miles. There are currently three pipelines that interconnect with the backbone system and carry natural gas to Sacramento: two PG&E lines and one SMUD pipeline. Those pipelines vary in length from 20-40 miles.

The essence of Sacramento's situation relative to its need for local storage of natural gas is that Sacramento is at the end of the pipelines, and they are branch lines at that. And, Sacramento has no backup supply capability to meet the needs of the metropolitan area if that supply were to be disrupted or reduced substantially. The residents of the area depend on natural gas as the source of 30+% of their electricity, and as their primary fuel for heating their homes and water, and cooking their food. Business and industry relies almost entirely on natural gas as their energy source, or else it is electricity that is produced almost entirely from burning natural gas. While the Sacramento area, like the rest of California, relies on natural gas as its fuel of choice, it has no backup supply in case there is a disruption in the flow of its normal supply line.

D2-257 (Cont.)

The possibility of a major disruption of service on the backbone system, either from natural or man-made causes, has not been the subject of public discussion. Our energy distribution systems throughout this country have not been developed with a high degree of concern for malicious activities -- they are relatively "soft" in that regard. The El Paso pipeline segment of the backbone system crosses from Arizona to California and is suspended over the Colorado River. Similarly, the Kern River pipeline segment is suspended over Kern River. These segments are clearly visible from public areas and permit activities in close proximity, e.g., the river itself. PG&E, like most utilities, is highly aware of such threats and is doing a good job of protecting their property and the public welfare. The potential for a significant physical disruption is nonetheless appreciable.

If there were to be a disruption or severe curtailment of supply on the main backbone system, one obvious response would be for the utilities to purchase "replacement" electricity from other sources outside the State and have it delivered by the electric grid system that serves northern California. The problem with that solution is that it would be a partial remedy, at best. At a time of disruption or curtailment, the whole of northern California, and perhaps the whole State, would be in a state of turmoil. The demand for the importation for such "replacement power" could not be handled by the existing

[5] On August 21, 2007 the Sacramento City Council approved Resolution No. 2007-623, a copy of which is provided as **Exhibit B** hereto, together with the Economic Development Department's overview of the "Clean Tech Zone" program.

electric grid which is not sized to handle 100% of such an event.

The original backup system for natural gas was to burn fuel oil for heat and electricity generation. That is no longer permitted by State law. At one time, Sacramento relied on nuclear power for much of its electric needs. That capability is no longer available. Utilities are making progress adding renewable energy source electricity to their capabilities, but it will be many years, if ever, before it can replace natural gas as the energy source of choice. For a metropolitan area that relies on natural gas, this is a perilous situation that can be improved dramatically by establishing a natural gas storage capability in our community.

Q11 ***Describe The Shortcomings Of The Existing Storage Facilities.***

The natural gas storage "system" for Sacramento does not exist as a system. Rather, storage is provided primarily by three separate storage facilities. The largest facility is the McDonald Island facility, owned and operated by PG&E. The other two facilities are independent, market-based rate facilities, at the Wild Goose storage facility in Butte Country, and the Lodi storage facility near Lodi. All of these facilities utilize the PG&E backbone system to get natural gas to the Sacramento area. Disruption of service on the backbone system or on any of the transmission lines from the backbone to Sacramento could render the stored gas useless to the Sacramento area for the period of the disruption.

The need for more reliable on-line storage is set forth in the accompanying testimony of SMUD's Barry Brunelle. See also the February 25 2008 letter from James R. Shetler, SMUD's Assistant General Manager Energy Supply, to Commissioner Simon and Administrative Law Judge Richard Smith, a true and correct copy of which is attached hereto as **Exhibit C.**

Q12 ***How Does the Proposed Project Solve These Problems?***

The proposed project is committed to provide storage by SMUD of a 30-day supply of natural gas which is sufficient to meet 100% of SMUD's electric generation requirements while using less than half the capacity of the facility.

Q13 ***What Is The History Of The Florin Gas Field?***

The Florin Gas Field was discovered in the 1970's by Union Oil Company. Five wells were drilled into the structure by Union Oil (3) and Proctor & Gamble (2).[6] Three other wells were drilled in the proximity (corner shoots) by Venada National (2) and TXO (1). All of the wells were drilled in the 70's and 80's. Abandonments were in the 80's and 90's. Three of the wells were drilled in what is now known as Danny Nunn Park. The other five were drilled in the industrial zone to the east.

During the 70's and 80's five seismic lines were shot to further delineate the field plus two other shots, which turned out to be remote from the field.

D2-257 (Cont.)

[6] Proctor & Gamble drilled under the name of "Quadren Energy."

Q14 ***How Was The Surface Boundary Of The Field Delineated?***

Our work began with a review of the well histories and production records that are available on-line from the DOGGR web site. From this, it was determined that of the eight wells drilled in the field, only five bottomed out in the gas sand. The bottom hole locations helped to delineate the field.

We engaged Rich Boyd to do a preliminary evaluation of the field. Thereafter, reservoir engineer John Matthews was engaged to review the well records and logs to provide initial assurance of the size, type and quality of the reservoir. At this point it was essential to bring in a premier engineering firm. Ryder Scott, an internationally renowned reservoir engineering firm, was employed to independently model and study the reservoir.[7] They utilized the well histories, well logs, production histories, and five seismic lines to delineate the field. From this data, they were able to construct a field model which is the basis for further development. Ryder Scott worked with the engineering firm of Andregg Geomatics to project the reservoir's boundaries onto the surface and delineate the field's boundaries on the surface. We used that map to locate property owners with whom we would need to execute storage leases. We made some adjustments to the map, enlarging the field's boundaries somewhat to be conservative and round out the boundaries. A true and correct copy of the map we developed delineating the field's surface boundaries is attached as **Exhibit D**.

Q15 ***Briefly Describe The Project As It Is Envisioned.***

The SNGS Natural Gas Storage project consists of three components. These are the reservoir, including the wells and water removal equipment, the compressor station, including compressors, metering facilities, dehydration and operation facilities and two short interconnecting pipelines. The project will lease pipeline capacity from SMUD for the transmission of gas from and into the PG&E system.

The proposed well site is located on a four acre parcel at the corner of Junipero Street and Power Inn Road. It overlays the 287 acre field just east of the center of the field. There will be six wells drilled from this site and horizontally completed about 3800 feet below ground surface. There will also be a water disposal well to return produced water to the reservoir and an observation well to monitor the reservoir.[8] The Compressor Station will be located on a five acre plot at Depot Park, the old Sacramento Army Depot.

Finally, there will be a pipeline from SMUD Line 700A to the compressor station and thence on to the well site (about a mile and a half total). The pipeline in Sacramento will

D2-257 (Cont.)

[7] Ryder Scott is a Houston-based firm that does reservoir engineering and simulation throughout the world. They provided a team of experts lead by Dean Rietz and modeled by Bruce Palmer with assistance from other Geophysicists, Geologists and Engineers.

[8] Halliburton has been employed to engineer the wells, obtain the required permits from the DOGGR, and manage the drilling program.

mostly be on the Army Depot in the north and underlie a SMUD and a PG&E electric easement in the South. It will cross under two city streets.

An aerial map showing the project components is attached as **Exhibit E.** A graphic presentation of the new injection/withdrawal wells is attached as **Exhibit F.**

Q16 ***Please Describe The Physical And Aesthetic Features Of the Well Site, Compressor Station, And Their Connecting Pipeline.***

To begin with, there will be no construction or any facilities in the residential neighborhood to the west of Power Inn Road. The well site is owned by SNGS. At the present time, it is a four acre parcel of weeds with two PG&E power lines with steel towers that occupy about an acre along the Power Inn frontage. Junipero Street on the south side is a privately owned street; the north half of the street is a portion of the well site property. The east three± acres will be enclosed in a decorative ten foot masonry wall with a gate on Junipero. All of the well site facilities will be inside the wall and will not be visible from the outside. There will be monitoring devices within the wall to prevent vandalism.

Curbs and gutters will be installed in keeping with City specifications on Power Inn and Junipero. Sidewalks will be constructed adjacent to the curbs. The area between the sidewalks and the wall will be covered with extensive landscaping. Preliminary renderings of this have been provided to the CPUC. One such rendering is attached as **Exhibit G.** A water and a sewer interconnect will be made, according to City standards, in Power Inn Road.

The pipeline from the well site to the compressor station will follow the PG&E easement to the SMUD east-to-west easement, and will thence traverse the SMUD easement to the Union Pacific Railroad. This will be buried with six feet of cover, twice the required depth. It will be a Class 3 pipeline (49 CFR 192.5), but will be constructed to the more conservative Class 4 design factor of 0.4 (49 CRF 192.111). Crossing of Berry Street, Elder Creek Road and the Railroad will be by sub-surface directional drilling. After it has crossed the railroad to Depot Park, it will be trenched at a coverage depth of six feet to the compressor station and thence to the interconnection with SMUD near Fruitridge Road.

The Compressor Station will occupy a five acre parcel in the Depot Park industrial complex. An Option to lease this parcel is in place. The parcel will be enclosed in an eight foot fence and the facility will be staffed at all times. Appropriate devices will be installed to monitor for any intrusions. The property will be surfaced with crushed rock. SNGS decided to utilize electric compression, so the Compressor Station's operation should be relatively quiet.

D2-257 (Cont.)

III. COMMUNITY VALUES

Q17 ***What Steps Are SNGS Taking To Protect And Advance Community Values?***

SNGS has every desire to be a highly valuable member of the local community. I will list and describe some of the distinct contributions the SNGS project will bring the community as follows:

First and foremost, the project will benefit the neighborhood and all of the Sacramento area, with a land use that is 100% in accordance with the City's General Plan. No above-ground facilities or operations will be located in the residential area west of Power Inn Road. All of the above-ground facilities are proposed to be located east of Power Inn Road on sites zoned for industrial development. See the Land Use Chart attached as **Exhibit H.**

Second, Sacramento Municipal Utility District ("SMUD") is the essential supplier of electric energy in the neighborhood and in Sacramento generally. The SNGS project will offer the following benefits to SMUD and its ratepayers:

- Provide some 30 days of backup and emergency gas supply at a critical location on the SMUD pipeline. At this location it will supply gas to SMUD's gas-fired power plants in the event of any upstream interruption or curtailment.
- Permit the stockpiling of gas when lower cost supply is available and thereby avoid the need to purchase supply when gas is in high demand at higher prices.
- Provide gas-powered generation to back up other sources of power.
- Relieve SMUD of any development or operating risks.

For additional details, please see the testimony of Barry Brunelle, SMUD's Supervisor – Gas Supply, which is being submitted concurrently with my testimony.

Third, SNGS's desire to ensure fair and equitable compensation for the landowners for the lease or sale of their storage rights caused SNGS to commission an independent appraisal of the current value of those storage rights by the recognized firm of Harold W. Bertholf, Inc. Appraiser, Engineer Geologist. A summary of that appraisal is included in Mr. Bertholf's testimony, which is being submitted concurrently with mine. Mr. Bertholf was initially engaged by SNGS to set a value on the storage rights underlying the 15± acres (including Danny Nunn Park) owned by the City. However, the appraisal actually sets forth the fair market rental for all storage rights at the Florin facility based on similar or "comparable" transactions in the northern California market together with the vast experience and expertise of Bertholf. It is the intent of SNGS to treat all landowners, including the City, on the same basis and without any price discrimination. Accordingly, SNGS is making an offer ("Offer") to all landowners including a signing bonus of $1,000 per acre but not less than $500 per parcel (a typical residential parcel occupies a site of

D2-257 (Cont.)

0.18 to 0.20 acre) and an ongoing annual rental beginning when the project goes on-line or March 31, 2009 whichever is sooner. The Offer provides a minimum annual rental of $1,000 per acre but not less than $500 per parcel against a percentage rent equal to the parcel's pro rata share of 4% of annual gross revenues generated by the project whichever is grated. We now estimate annual gross revenues of approximately $17,600,000 which would generate a total percentage rent of $704000 or approximately $2450 per acre for the 287 acre site. The SNGS Offer is more favorable to the landowners than the Bertholf appraisal as set forth in the accompanying testimony of Don Russell.

Fourth, the lease provides substantial benefits and protection to the landowners, including a 4% annual CPI rental adjustment, indemnity against damages, liability insurance, periodic payment for any pre-existing gas that might be produced by SNGS, and a seven day "cooling off period" for landowners who decide to walk away from the deal. A true and correct copy of our standard residential lease is attached as **Exhibit I.**

Fifth, as there are a number of residents in the area who live adjacent to the gas storage reservoir but not over it (and are therefore not eligible to receive storage rights lease payments), SNGS proposes to establish and fund a Community Foundation to support projects or activities that will benefit the entire local community. SNGS has pledged annual funding of .25% of annual gross revenues generated by the Project. An outline of the basic structure of the Community Foundation is attached as **Exhibit J.** In addition to the Foundation, the City representatives have agreed informally to use the City's annual rental income for its 15± acres ($15,000±/yr minimum, $37,500/yr expected) for maintenance and improvements to the Danny Nunn Park.

Sixth, SNGS has proposed to expand its security service patrol to include Danny Nunn Park and the George Sims Community Center and also to work with the members of the Power Inn Alliance to unify and coordinate the SNGS security patrol with other security patrol services now in place and thereby strengthen and enhance overall community security.

Seventh, SNGS has entered into a project labor agreement with Sacramento-Sierra's Building and Construction Trades Council to ensure that the project is constructed with union labor. As many of the residents of the local community are members of various labor unions, this will provide additional wage and benefits to some of those individuals. A true and correct copy of that agreement is attached as **Exhibit K.**

Eighth, the overall economic benefit to the community has been computed by Dr. Robert Fountain, whose report and testimony are being submitted concurrently with my testimony, generally to the effect that the project will bring one-time economic benefits to the City of almost $78,000,000 during the construction phase of the project and almost $25,000,000 annually thereafter during operations.

Ninth, SNGS has determined that the project will not increase the cost of homeowner insurance, nor cause any loss of residential property values. The testimony of insurance actuary Shawna Ackerman, MAI appraiser Arthur Gimmy and residential market analyst John Schleimer to this effect is being submitted concurrently with my testimony.

D2-257 (Cont.)

Tenth, SNGS has already demonstrated its willingness to financially support various local charitable and non-profit service organizations, including, among others, the local soccer league, the St. Johns Shelter for Women and Children, and the Power Inn Alliance. The management of SNGS is committed to continue and enlarge such support in the future.

Eleventh, SNGS has engaged the Hoyt Company of Sacramento to conduct a comprehensive community outreach program to inform the neighborhood as to all aspects of the project. This has included project newsletters (in multiple languages), private meetings with community representatives, and public meetings and presentations for the public generally. Please see the concurrently submitted testimony of Wendy Hoyt for details regarding our community outreach program.

Twelfth, and finally, the results of the SNGS outreach and the recognition by the local residents of the value of the project are best demonstrated by the fact that 565 owners of 414 parcels had executed storage rights leases as of August 18, 2008.

Q18 ***Please Describe The Basic Concepts And The Terms And Conditions Of The Storage Lease Agreement Between SMUD And SNGS.***

As previously stated, SMUD had been actively seeking natural gas storage capabilities since as early as 1992, when it issued a Request for Proposals from developers to develop an underground natural gas storage facility to serve SMUD's needs. I believe that since the mid-1990's, SMUD has been and still is a storage customer at the Wild Goose storage facility in Butte County. SMUD, however, has still been looking for "on-system" storage, which is what the SNGS facility will provide.

The negotiations with SMUD began in the fourth quarter of 2006 and continued on into the first quarter of 2007. SMUD's objectives were to obtain increased reliability of supply, increased operational flexibility, and the ability to arbitrage prices of fuel. These negotiations were successful and resulted in a comprehensive Natural Gas Storage Services Agreement unanimously approved by the SMUD Board of Directors on March 7, 2007. This Agreement is, of course, subject to the requirements of the California Environmental Quality Act, a Certificate of Public Convenience and Necessity from the CPUC, DOGGR approval, and the necessary use permits and approvals by local agencies.

As a simple benchmark, the Agreement provides SMUD with enough storage capacity, and injection and withdrawal volumes, to keep their four generating plants running for about 30 days. Accordingly, the Agreement gives SMUD access, under varying terms and conditions, to about half of the total storage capacity of the SNGS facility. As such, SMUD is a 20-year "anchor tenant" and has demanded and received a storage rate that SNGS considers to be "sub-market" at this time.

Q19 ***Are There Other Prospective Customers?***

SNGS is in discussions with Roseville Electric, Sacramento Regional Transit and a variety of private entities for use of the SNGS facility.

D2-257 (Cont.)

IV. INTERCONNECTION WITH PACIFIC GAS AND ELECTRIC ("PG&E) SYSTEM.

Q20 ***What Is The General Status Of The Resolution Interconnection Issues With PG&E?***

As of September 2, 2008, SNGS and PG&E have resolved in principle all of the issues originally raised by PG&E. To support resolution of the interconnection issues, SNGS has decided to eliminate the proposed interconnection with PG&E Line 172 as an element of the proposed SNGS Facility. SNGS reached this decision after further discussions with PG&E indicated that the proposed interconnection at Line 172 would increase both the cost and the complexity of the interconnection between SNGS and PG&E.

Q21 ***Are The Proposed SNGS Metering And Odorization Facilities Consistent With PG&E's Standard Practice For Interconnections With Independent Storage Providers And With PG&E's Tariffs?***

SNGS is prepared to satisfy all standard practices of PG&E with respect to metering and odorization facilities, and to comply with applicable PG&E tariffs, including those applicable to direct customer and producer connections to independent gas storage service providers. To accommodate the increased range of flows at the Line 400/401 and Line 700 interconnection that will result from the proposed SNGS Facility, SMUD, as owner of the meter station, has proposed meter station design modifications. With certain potential refinements to assure the desired functionality and compliance with all industry standards and regulatory requirements, SNGS, SMUD and PG&E have agreed in principle to SMUD's proposed engineering design and are proceeding to resolve the remaining detailed engineering design specification issues. PG&E, SMUD and SNGS have agreed in principle that SMUD, as owner, will contract with a third-party contractor that is also approved by PG&E and SNGS to undertake the installation, with supervision by PG&E. We also have agreed in principle to the allocation of the installation costs.

SNGS is preparing a further amendment to its Amended Application filed in this proceeding on October 9, 2007 for that purpose. The amendment will not affect the Commission's ongoing environmental review of the remaining proposed SNGS Facility elements.

Q22 ***Should SNGS Be Limited To The Points Of Interconnection Described In Its Application To Prevent The SNGS Facility From Being Used To Bypass PG&E's Transportation Rates And Charges?***

It is not necessary to preclude direct customer connections to avoid bypass of PG&E's transportation rates and charges. SNGS will stipulate that all deliveries from the SNGS Facility to any customer of SNGS (other than SMUD) or producer that is directly connected to the SNGS Facility will be metered by PG&E and subject to all applicable PG&E tariffs, pursuant to the Independent Storage Provider Interconnections Settlement Agreement approved in the Gas OIR, R.04-01-025. It is the understanding of SNGS that PG&E concurs with this approach.

D2-257 (Cont.)

Q23 ***Should SNGS Be Required To Execute An Operating And Balancing Agreement With PG&E Like Those With Other Storage Providers?***

SNGS and PG&E have agreed in principle that the upgraded meter at the existing Line 400/401 and SMUD Line 700 interconnection will be the "meter of record" for deliveries for the SNGS account with PG&E, and that deliveries scheduled by SNGS to or from the PG&E system will be deemed to be delivered. Under this approach, the interconnection will continue to be operated in accordance with the existing operating agreement between PG&E and SMUD. SNGS will enter into an operating agreement with SMUD which provides for any necessary balancing beyond the PG&E delivery point. This will avoid the need for PG&E to administer separate balancing accounts with SNGS and SMUD. PG&E and SNGS have agreed to work together to clarify the nomination process and protocols required for storage transactions on PG&E's system.

Q24 ***Should SNGS Be Required To Confirm, Subject To Audit, That Gas Nominated For Delivery Onto The PG&E System Originated On The PG&E System Before Being Placed Into The Storage Field?***

Yes. SNGS has agreed not to do anything that results in any bypass of PG&E's authorized tariffs or rates.

Q25 ***Should Applicant Be Required To Ensure That The British Thermal Unit (Btu) Content Of Gas It Delivers To PG&E's Local Transmission System Is Within PG&E's Tolerance Levels For The Btu Billing Zone In Which It Is Delivered?***

The decision by SNGS to eliminate the proposed interconnection with PG&E Line 172 from the design of the proposed SNGS Facility moots this issue.

Q26 ***Should SNGS And Its Customers Be Required To Bear 100% Of The Risk For The Costs Of The Proposed Construction And Operation Of The SNGS Facility, Including Costs For PG&E To Construct And Install Metering, Odorization, And Other Facilities For The Interconnection Of The SNGS Facility To PG&E, And Costs For Changing PG&E's Computer And Allocation Modeling Systems To Accommodate Operation Of The SNGS Facility?***

SNGS agrees that it and its customers should be required to bear 100% of the risk for the costs of the proposed construction and operation of the SNGS Facility, including PG&E's costs to modify its computer system to accept SNGS transactions. The one identified exception to SNGS bearing 100% of the costs is that SNGS, PG&E and SMUD have agreed in principle to share the costs to modify the metering equipment at the Line 400/401 and Line 700 interconnection. This cost sharing reflects the recognition that each entity will derive benefits from increasing the functionality and accuracy of the metering equipment.

Q27 ***Does That Conclude Your Testimony?***

Yes.

D2-257 (Cont.)

EXHIBIT A

SMUD
SACRAMENTO MUNICIPAL UTILITY DISTRICT ☐ P. O. Box 15830, Sacramento CA 95852-1830, (916) 452-3211
AN ELECTRIC SYSTEM SERVING THE HEART OF CALIFORNIA

June 5, 1992
FD 92-081

Company
Address
City, State, Zip Code

REQUEST FOR PROPOSALS (RFP) FOR SALE OR PARTICIPATION IN A NATURAL GAS STORAGE PROJECT; SACRAMENTO MUNICIPAL UTILITY DISTRICT

The Sacramento Municipal Utility District (SMUD) is in the process of acquiring natural gas supplies to fuel a number of new gas turbine cogeneration power plants to be located near Sacramento. The plants are scheduled to come "on line" beginning in July, 1994. Our Fuel procurement strategy includes participation in a reliable gas storage project which is capable of meeting our peaking needs. The District intends to reduce delivered fuel costs and improve peak/swing flexibility with the benefit of gas storage.

The attached RFP provides the necessary information for interested parties to complete proposals for SMUD's consideration. We call your attention to the summary "Screening Questionnaire", Attachment I, on Page 8, immediately following the main body of the RFP discussion and ask that it be completed in full. The District intends to work from this Questionnaire to expedite the evaluation process. Finally, note the time schedule of the RFP process on Page 2, and in particular the July 31 due date for submitting proposals.

Questions should be directed to Mr. Thomas Ingwers, Senior Natural Gas Specialist, at (916) 732-6229 or the undersigned at (916) 732-6553.

Sincerely,

R. B. Minter, Manager
Fuels Development Department

Attachments

D2-258

SACRAMENTO MUNICIPAL UTILITY DISTRICT

REQUEST FOR PROPOSALS (RFP)
FOR PARTICIPATION IN A
NATURAL GAS STORAGE PROJECT
RFP NO. 91-2

I. INTRODUCTION

The Sacramento Municipal Utility District (SMUD or the District) is soliciting proposals for participation in, or sale of, a natural gas storage project to help satisfy future natural gas capacity requirements for fueling several new gas turbine cogeneration power plants. SMUD intends to negotiate with Respondents whose projects, in the District's sole judgement, will provide the greatest value to the District's customer-owners when compared to other proposals. SMUD reserves the right to reject any and all proposals.

II. SCHEDULE AND DESCRIPTION OF THE SOLICITATION PROCESS

The solicitation process will begin with the mailing of the Storage RFP on June 5, 1992 and will continue until 5:00 P.M. Pacific Standard Time on July 31, 1992, which is the closing date for the submission of proposals. RFP responses received after 5:00 P.M. Pacific Standard Time on the closing day may be deemed non-responsive and given no further consideration.

Responses and any questions relating to this RFP, if mailed, shall be addressed as follows:

MAILING ADDRESS:
SMUD RFP NO. 91-2, GAS STORAGE
FUELS DEVELOPMENT DEPARTMENT
Mail Stop 49
P. O. Box 15830
Sacramento, California 95852-1830

D2-258 (Cont.)

Responses or written inquiries relating to this RFP, if couriered or hand-delivered, shall be addressed as follows:

COURIER ADDRESS:	*SMUD RFP NO. 91-2, GAS STORAGE* *FUELS DEVELOPMENT DEPARTMENT* *6201 "S" Street, Mail Stop 49* *Sacramento, California 95817-1899*

Each proposal shall be delivered in envelopes, boxes, etc., that are marked RFP No. 91-2 and will be date stamped upon receipt. All proposals shall be submitted in triplicate. Questions and/or communications regarding this RFP shall be directed to Mr. Thomas Ingwers, Senior Natural Gas Specialist, at (916) 732-6229 or Mr. R. B. Minter, Fuels Manager, at (916) 732-6553.

The full schedule for the RFP process is as follows:

DATE	*EVENT*
June 5, 1992	*Distribute RFP*
July 31, 1992	*Proposals Due*
August 31, 1992	*Notify Respondent(s) Selected for Negotiations*

D2-258 (Cont.)

III. EVALUATION PROCESS

The Fuels Department staff will provide initial screening of proposals; however, we intend to select a firm specializing in gas storage operations to identify our best candidate(s). Factors such as the project reservoir characteristics, stage of development, Respondent's experience in operating other storage facilities, cost of service, capacity, fuel deliverability, location, the District's exposure to risks and other factors will be used to determine the overall value of the proposal to the District. Please reference the detailed data request under Section VI - Format and Proposal Content beginning on Page 4, and the summary "Screening Questionnaire", Attachment I, on Page 8. The completed Questionnaire will allow the District to expedite the evaluation process and to confirm compliance with the Minimum Requirements set forth in Section V. below.

IV. GENERAL PROVISIONS

All proposals submitted in response to this RFP must be valid for acceptance until December 31, 1992. The District reserves the right to deem any proposal with incomplete responses as non-responsive and to give it no further consideration. The District may request clarification of incomplete responses to an item, or to seek additional clarification of information. Failure of a Respondent to provide such information in a timely and sufficient manner will result in that proposal being deemed non-responsive with no further consideration given. All proposals and supporting documentation shall become the property of the District.

V. MINIMUM REQUIREMENTS

At a minimum, all storage projects must possess the following characteristics to be eligible for further review:

A. **Location** - *The Storage Project must be located close enough to Sacramento to allow a economically feasible direct interconnection to SMUD's proposed local gas transportation pipeline system.*

B. **Reliability of Service** - *Storage service must be highly reliable and not be subject to service curtailment or reservoir leakage or transport curtailment.*

C. **Withdrawal/Injection Capability** - *The Storage Project must provide SMUD with minimum withdrawal capability of 125 MMCFD for a minimum of ten consecutive days. The Storage Project must provide SMUD with minimum injection capability of 65 MMCFD for thirty consecutive days.*

D. **Storage Capacity** - *The storage project must be capable of storing a minimum of 3 BCF of SMUD working gas (approximately 45 days of projected supply under average conditions).*

E. **Project Timing** - *The Storage Project should be operable not sooner than July, 1994 or later than January, 1997.*

F. **Respondent Qualifications** - *If the Respondent proposes to offer storage on a contractual basis, it must be financially sound and have experience in i) developing and operating gas storage facilities, or be committed to hire personnel with experience in this area, ii) drilling and operating gas wells, and iii) operating and constructing pipelines, compressors and related facilities.*

D2-258 (Cont.)

If the Respondent proposes to sell a storage project, it must have experience in developing gas fields and a thorough understanding of gas storage reservoir requirements and development requirements.

G. ***Free of Encumbrances and Impediments*** *- The Gas Storage Project must i) be capable of meeting all regulatory requirements and able to obtain all required permits, ii) have marketable title, iii) be free of environmental contamination and pending litigation, and iv) have the necessary landowner and mineral owner storage agreements in place.*

VI. FORMAT AND PROPOSAL CONTENT

GENERAL INSTRUCTIONS

In addition to completing the Screening Questionnaire, Attachment I, the following information is required to provide the necessary detail for project evaluation. Failure to respond fully may result in the proposal being deemed non-responsive with no further consideration given. Respondents should thoroughly review their proposals for completeness and accuracy to assure acceptability.

D2-258 (Cont.)

A. GENERAL INFORMATION REGARDING RESPONDENT.

Provide a general description of the Respondent's "organization" to include all prospective participants - Respondent, landowner, operator, financier, etc. This information should include the names and addresses of the Respondent, principals and all other aforementioned participants in the "organization". If the Respondent is a corporation, identify officers, state of incorporation, and the parent corporation. If the Respondent is a partnership, the general partner shall be listed and the state(s) in which the partnership is filed shall be identified. Provide the name, title, mailing address, phone number, and facsimile machine number of the appropriate contact person(s) to answer questions and conduct negotiations related to this proposal.

B. QUALIFICATIONS OF RESPONDENT

Provide a discussion and description of Respondent's qualifications and experience in developing and operating i) natural gas storage projects, ii) natural gas producing wells, and/or iii) natural gas pipeline systems.

C. *DESCRIPTION OF STORAGE PROJECT*

Provide overview. Also include detailed, relevant engineering information. Respondents should use this Section (VI) and the Attachment I, Screening Questionnaire, beginning Page 8.

D. *TERMS OF PARTICIPATION OR SALE*

Provide relevant cost of service information or terms of sale.

E. *GAS AND WATER COLLECTION, TREATING, TRANSMISSION FACILITIES*

Provide an inventory of pipeline transmission facilities to include compression, gas or water treatment, water disposal, water collection, etc., or other appurtenances attached thereto, that are to be included in a sale, if applicable. Respondent should discuss age and condition of these facilities and the years until replacement is required. Also discuss project access to PG&E or other pipeline collection systems.

F. *PERFORMANCE GUARANTEES*

Describe in detail any type of security or any other forms of performance guarantee which would be provided to the District.

G. *CONTRACTS*

Provide copies of any existing gas sales, pipeline contracts, or other contracts which may impact or encumber Respondent's interest in the project.

H. *STORAGE AGREEMENT/OIL AND GAS LEASE*

Provide a copy of the Storage Agreement with the surface and mineral owner, all underlying oil and gas leases, and all other agreements related to the gas storage project, to include current gas in place within the storage reservoir.

I. *LITIGATION*

Provide summary of any prior or ongoing litigation pertinent to Respondent or Respondent's "organization" and his, or their, collective ability to carry out this proposal.

D2-258 (Cont.)

J. *ENVIRONMENTAL*

Provide copy of any environmental audits or reports conducted on the lands covered by the storage agreement or oil and gas leases. Respondent should discuss anticipated environmental impact of project. Also outline plans and costs to deal with possible "offsets" related to compression and work anticipated to meet guidelines of appropriate governmental agencies.

K. *TITLE*

Provide copy of a Title Policy or Title Opinion evidencing Respondent's interest in the storage project and evidence that Respondent's interest is free of liens and encumbrances. Provide copy and list the terms of existing notes or other obligatory financial contracts, liens or similar encumbrances which will continue to encumber any portion of the project properties after closing.

L. *GAS QUALITY*

A representative, current gas analysis is required. Existing gas reserve should be free of corrosive elements or other contaminants unsuitable for burning in a gas turbine.

M. *OTHER*

Discuss any special circumstances or possible problems such as difficulty in "isolating" the storage reservoir, water production and handling, sumps, injection wells, noise, wetlands, flooding, contaminants or other concerns that may have impact on value of the project.

VII. *PURCHASE AND SALE AGREEMENT*

Any participation in storage capacity by SMUD as a result of this RFP process is expressly subject to the execution of a definitive Purchase and Sale Agreement in a form satisfactory to the District. Such Purchase and Sale Agreement shall include among others, the following provisions:

A. *A special warranty of title provision whereby Seller warrants title to the real and personal property as against any party claiming by, through or under Seller.*

D2-258
(Cont.)

B. *An environmental indemnity provision whereby Seller shall indemnify, defend, and hold harmless the District, SMUD Directors, officers, agents, and employees against all claims, loss, damage or expense relating to any hazardous or toxic materials which were present on the property prior to the District's involvement.*

D2-258
(Cont.)

ATTACHMENT I

SCREENING QUESTIONNAIRE

1. *LOCATION. Note project distance from Sacramento. Identify Township, Range and Section(s) involved.* ___ *Miles*

   _____
   _____
   _____

2. *PROJECT STAGE OF DEVELOPMENT. Check appropriate boxes for COMPLETED stage(s):*

   A. *Gas reserves within the storage project have been leased or purchased by Respondent.* ☐

   B. *Surface of the land applicable to project has been leased/ contracted or purchased by Respondent.* ☐

   C. *Separate storage agreement is in place between Respondent and landowner/mineral owner. Note expiration date_____.* ☐

   D. *Title Policy or Title Opinion has been prepared for the project.* ☐

   E. *Geological engineering study complete.* ☐

   F. *Reservoir engineering study complete.* ☐

   G. *Environmental engineering study complete.* ☐

   H. *Drilling engineering study complete.* ☐

   I. *Surface Facilities engineering study complete.* ☐

   J. *Experienced Project Operator in place.* ☐

   K. *Financing is in place.* ☐

D2-258 (Cont.)

L. *Independent Storage Analysis has been completed by firm specializing in Gas Storage.* ☐

3. *STORAGE VOLUMES. List approximate size:*

A. *Working Gas* _____*BCF*

B. *Cushion Gas* _____*BCF*

4. *WITHDRAWAL/INJECTION CAPABILITY*

A. *Withdrawal Capability* _____*MMCFD*

B. *Injection Capability* _____*MMCFD*

5. *AVERAGE BTU CONTENT OF EXISTING GAS IN PLACE.* _____*BTU/CF*

6. *NUMBER OF WELLS WITHIN PROJECT AREA:*

A. *Abandoned* _____*wells*

B. *Idle* _____*wells*

C. *Currently producing:* _____*wells*
*Average MCFD*_____ *Average BWPD*_____

D. *Newly drilled wells required.* _____*wells*

E. *Intended recompletions or cleanout of existing wells.* _____*wells*

7. *PROJECT RESERVOIR CHARACTERISTICS:*

A. *Average depth.* _____*Feet.*

B. *Number of separate storage intervals.* _____*Zones.*

D2-258 (Cont.)

C. *Trapping mechanism.* _____.
(ex. structural, fault, etc.)

D. *Influencing reservoir mechanism.* _____.
(ex.depletion drive, water drive, etc.

E. *Maximum past or historic production rate from reservoir.* _____*MMCFPD.*

F. *Original reservoir pressure.* _____*PSIA.*

G. *Current reservoir pressure.* _____*PSIA.*

H. *Original Gas in Place (GIP),* _____*BCF.*
storage zone(s).

I. *Current GIP, storage zone(s).* _____*BCF.*

J. *Estimated recoverable gas reserves.* _____*BCF.*

D2-258 (Cont.)

8. *ESTIMATED CAPITAL COST TO DEVELOP:*

A. Wells

1) Cost of New wells. $_____

2) Rework of existing wells. $_____

3) Abandonment or re-abandonment of existing wells. $_____

Well Cost Total $_____

B. Surface Facilities - Compression, land etc. $_____.

C. Gas transmission lines, outside project area. $_____.

D. Environmental $_____.

E. *Cushion Gas.* $_____.
Volume _____ BCF, Unit Cost _____ $/MCF

F. *Other* $_____.

Estimated Total Capital $_____.

9. *RESPONDENT'S GENERAL PROPOSAL TO SMUD. Indicate whether proposal A, B, C, and/or D is most appropriate:*

A. *SMUD rent/lease space. Also indicate Respondents proposed cost of service to SMUD and whether service is "firm" or "interruptible".* ☐

1) Reservation Fee _____$/MCF.

2) Injection/Withdraw Fee _____$/MCF.

B. *SMUD purchase equity interest. Briefly summarize proposal:* ☐

C. *SMUD develop and finance completely. Briefly summarize:* ☐

D. *Other. Briefly summarize:* ☐

D2-258 (Cont.)

10. *INDICATE POSITIVE OR NEGATIVE TO FOLLOWING QUESTIONS:*

	YES	NO
A. *Any known legal encumbrances which could involve project?*	☐	☐
B. *Any known environmental problems left from past producing operations?*	☐	☐
C. *Any known or possible environmental problems expected from project construction to include facilities, lines, noise, contaminants, water handling, etc.? If so, discuss.*	☐	☐

D2-258 (Cont.)

	YES	NO
D. *Any competitive wells on adjacent lands that could "interfere" in subsurface with Respondents project?*	☐	☐
E. *Are all past producing well records available - drilling and completion records, production histories, etc. - for SMUD and/or third party review?*	☐	☐

EXHIBIT B

RESOLUTION NO. 2007-623

Adopted by the Sacramento City Council

August 21, 2007

APPROVING A RESOLUTION IN SUPPORT OF CLEAN TECHNOLOGY INDUSTRY DEVELOPMENT IN THE SACRAMENTO REGION

BACKGROUND

A. On April 3, 2007, the Sacramento City Council reviewed and commented on the City of Sacramento's (City) draft Sustainability Master Plan (Plan). The Plan was formulated in response to the City Council's earlier direction to develop a Sustainability Agenda with goals and objectives to move the City towards using natural resources efficiently to prevent pollution and to improve the economic, environmental and social well-being of current and future generations.

B. On May 29, 2007, the City Council adopted an updated Economic Development Strategy containing strategic objectives and related action steps. Amongst the action steps is the targeted business attraction of high-value industries, including clean technology and renewable energy.

C. The future development of the clean technology industry within the Sacramento Region holds significant potential for realizing the goals and objectives of the Plan and the Economic Development Strategy.

D. The Partnership for Prosperity is a regional effort by the public and private sectors in the six-county Sacramento region to create a shared business agenda with focused economic development strategies that leverage the region's competitive advantages, unique strengths, and market opportunities. Business development, post-secondary education and high school education, civic amenities, and clean energy technology have been identified as the four priority opportunities to be addressed, coordinated, and aligned.

E. Within Partnership for Prosperity, a Clean Energy Technology Action Team has been formed, which includes representatives from throughout the region, that is developing strategies to increase clean-energy related academic and private sector research, start-up companies, investment capital and education infrastructure. The Clean Energy Technology Action Team seeks to increase public awareness that clean technology is a vibrant growth industry that will create thousands of jobs in the Sacramento region in the future.

D2-259

BASED ON THE FACTS SET FORTH IN THE BACKGROUND, THE CITY COUNCIL RESOLVES AS FOLLOWS:

Section 1. The City of Sacramento recognizes and fully supports the environmental, social and economic benefits related to development of the clean technology industry within the Sacramento Region.

Section 2. The City recognizes and supports the regional Partnership for Prosperity initiative and the efforts of its Clean Energy Technology Action Team.

Adopted by the City of Sacramento City Council on August 21, 2007 by the following vote:

Ayes: Councilmembers Fong, McCarty, Pannell, Sheedy, Waters, and Mayor Fargo.

Noes: None.

Abstain: None.

Absent: Councilmembers Cohn, Hammond, and Tretheway.

Heather Fargo
Mayor, Heather Fargo

Attest:
Shirley Concolino
Shirley Concolino, City Clerk

D2-259 (Cont.)

EXHIBIT C

S.C.SL.

SMUD
SACRAMENTO MUNICIPAL UTILITY DISTRICT
The Power To Do More.℠

P.O. Box 15830, Sacramento, CA 95852-1830; 1-888-742-SMUD (7683)

February 25, 2008
AGM/ES 08-009

Presiding Commissioner Timothy Alan Simon
California Public Utilities Commission
Attn: ALJ Richard Smith
505 Van Ness Avenue
San Francisco, CA 94102-3298

CPUC PROCEEDING A0704013; SACRAMENTO NATURAL GAS STORAGE PROJECT

Dear Commissioner Simon:

This letter is to affirm the support of the Sacramento Municipal Utility District ("SMUD" or "the District") for the application of Sacramento Natural Gas Storage, LLC ("SNGS") for a *Certificate of Public Convenience and Necessity* to construct and operate a natural gas storage facility in the now depleted Florin Gas Field in Sacramento.

The SNGS project will offer the following benefits to SMUD:

D2-260

- Provide about 30 days of back-up and emergency gas supply at a critical location on the SMUD pipeline. At this location it will supply gas to SMUD's gas-fired power plants in the event of any upstream disruption or curtailment for any reason such as pipeline maintenance, accident, terrorist activity, or other supply disruption on the PG&E backbone gas transmission system. These plants combined make up the majority of SMUD's average daily load.

- Permit the stockpiling of gas when lower cost supply is available and thereby avoid the need to purchase supply when gas is in high demand at higher prices.

- Provide reliable supply for "peaker plants" on the SMUD system.

- Provide gas-powered generation to back up solar, wind, and other alternative sources of power.

For these reasons, SMUD has entered into a long term Gas Storage Services Agreement with SNGS, subject to issuance of all necessary approvals, including the *Certificate of Public Convenience and Necessity* and ultimate completion of the actual facility, all on a timely basis.

SMUD has entered into this Storage Agreement with the expectation that the Commission and other regulatory agencies will undertake a full and complete investigation to ensure that public health and safety and the environment will be adequately protected in connection with the development of the SNGS facility. We are confident that all such issues will be fully examined during the course of these proceedings and SMUD will, of course, abide by the outcome.

SMUD is hopeful that this process will be completed this year so that this much needed project can be brought on line in 2009. If you have any questions about SMUD's position in this matter, please call me personally at 916-732-6757.

Sincerely,

James R. Shetler

James R. Shetler
Assistant General Manager
Energy Supply

D2-260 (Cont.)

EXHIBIT D

SACRAMENTO
Natural Gas Storage

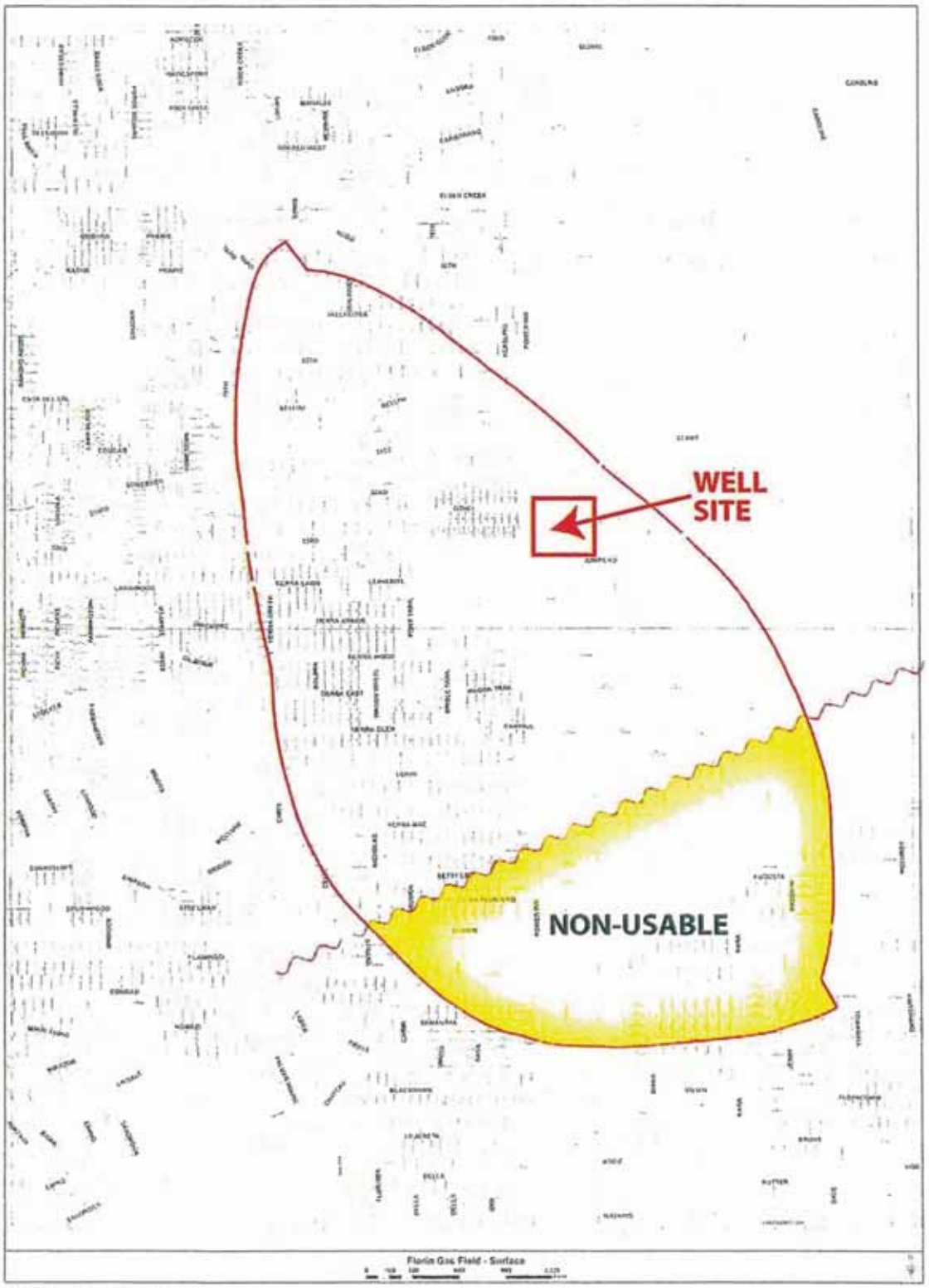
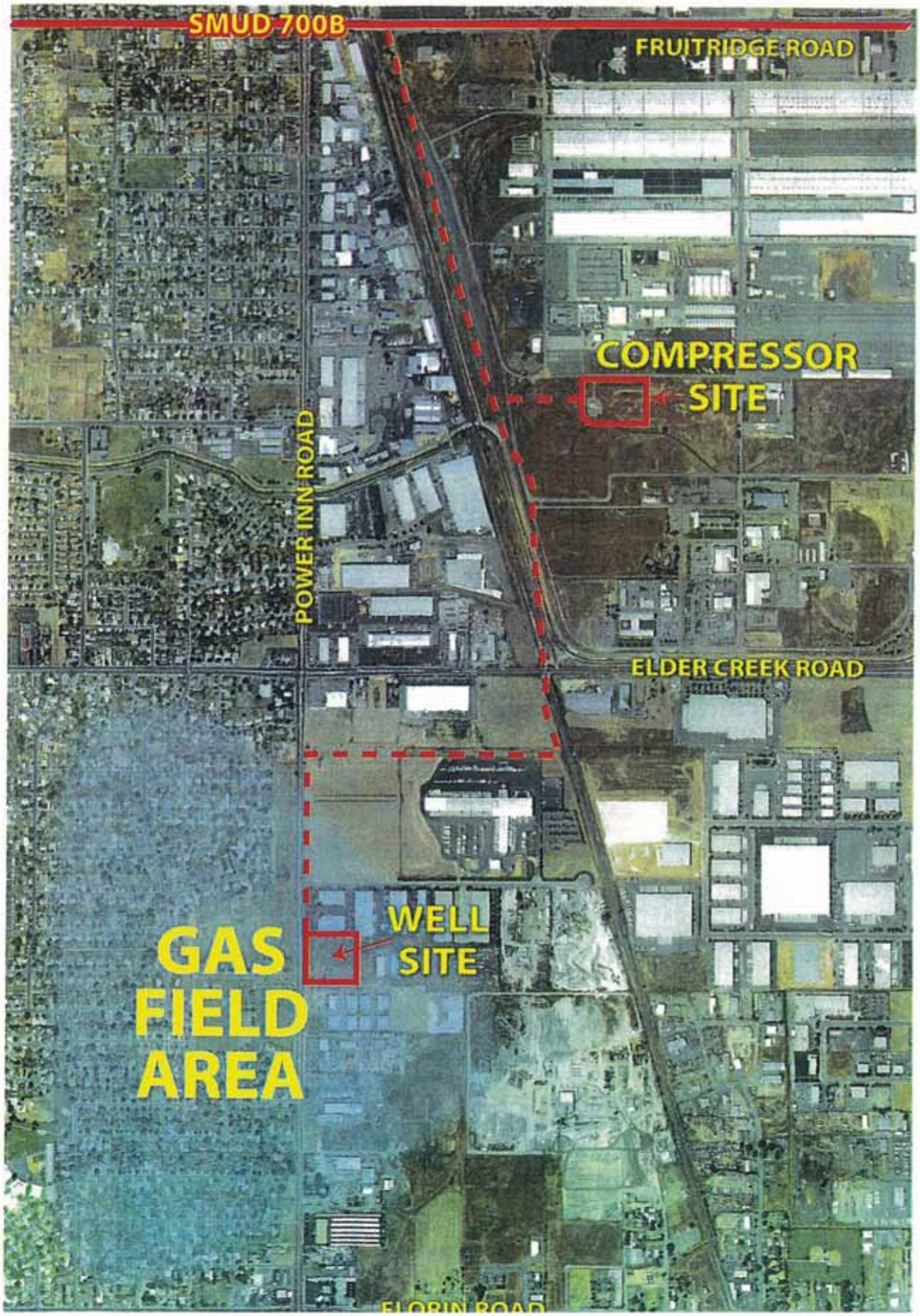


Exhibit Document: Not to Scale

D2-261

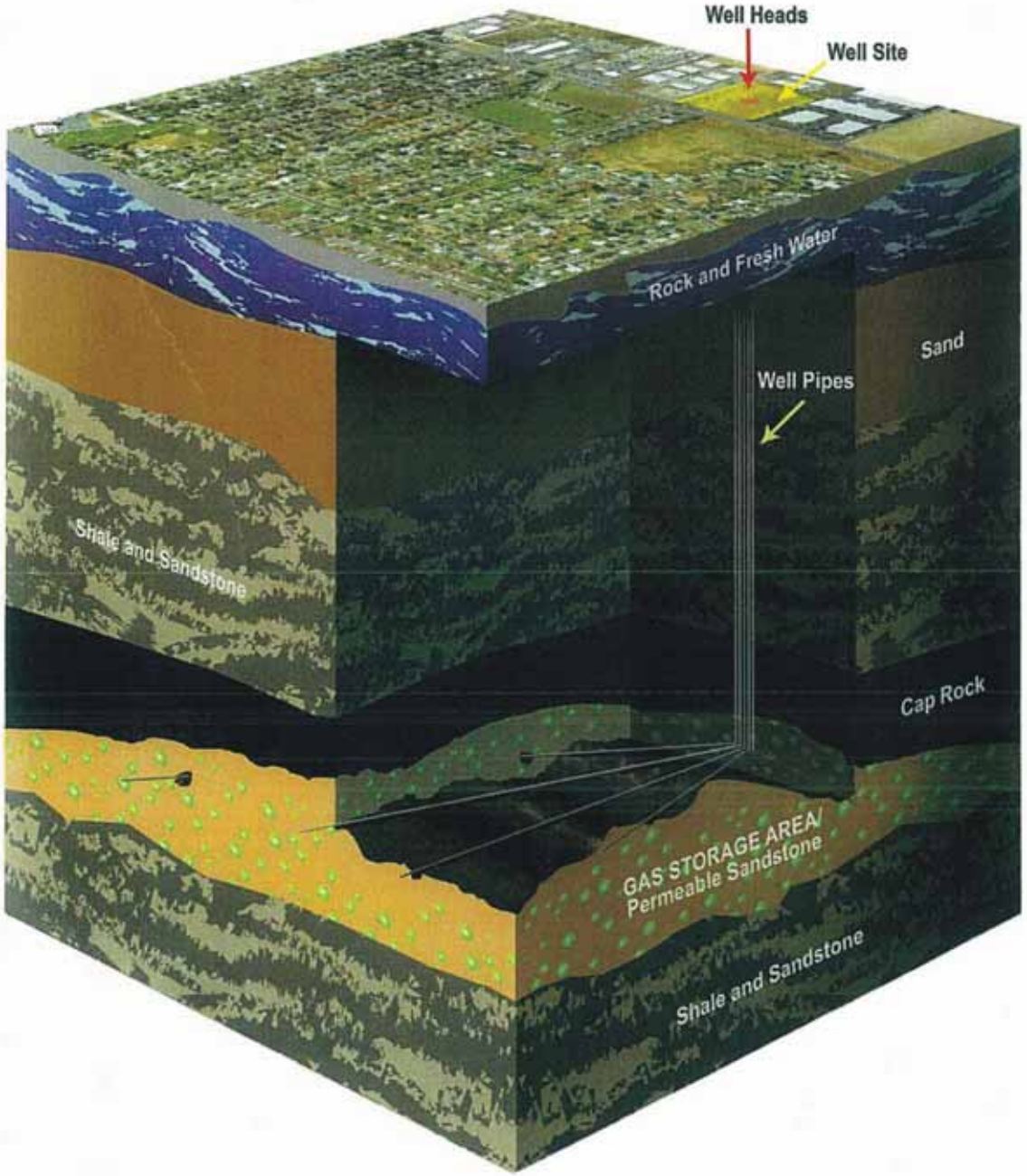
EXHIBIT E

Natural Gas Storage



D2-262

EXHIBIT F


Well Heads
Well Site
Rock and Fresh Water
Sand
Well Pipes
Shale and Sandstone
Cap Rock
GAS STORAGE AREA/
Permeable Sandstone
Shale and Sandstone

D2-263

EXHIBIT G

SACRAMENTO
Natural Gas Storage

WELL SITE ENCLOSURE



NLA
nacht & lewis
architects

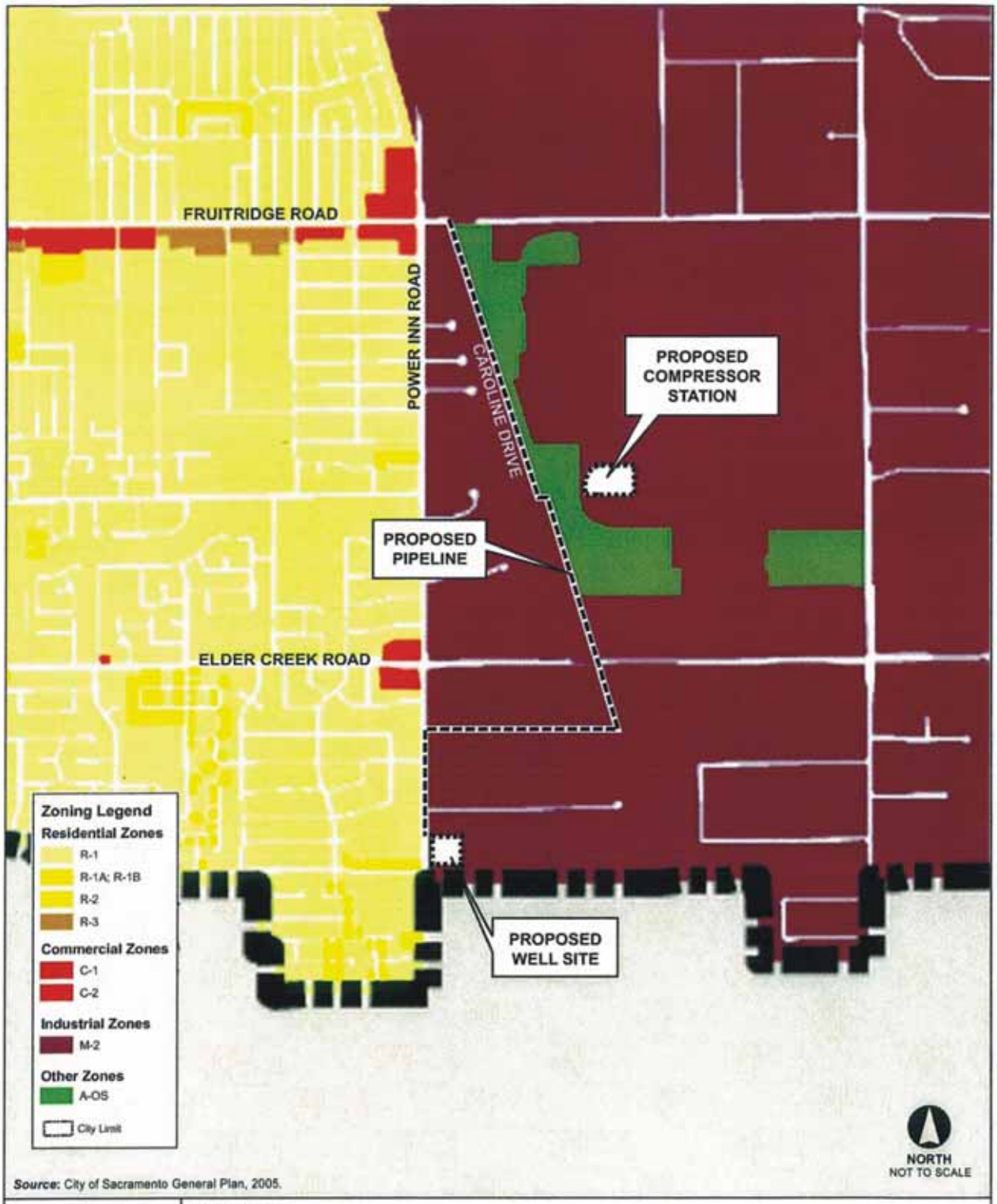
Property Enclosure
Power Inn Road and Junipero Street
Sacramento, California

A3

February 23, 2007

D2-264

EXHIBIT H



Source: City of Sacramento General Plan, 2005.

EIP

A division of PBSJ

FIGURE 3.9-1
Existing Zoning

D41288.00

Sacramento Natural Gas Storage Project PEA

D2-265

EXHIBIT I

UNDERGROUND GAS STORAGE LEASE AND AGREEMENT
(Residential)

THIS UNDERGROUND GAS STORAGE LEASE AND AGREEMENT ("Storage Agreement") is made and entered into effective this ___ day of _____, 200__, by and between _____ ("Lessor"), and Sacramento Natural Gas Storage, LLC, a California limited liability company, its successors and assigns ("Lessee").

WITNESSETH:

1. Lessor, for and in consideration of the payments provided below and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, hereby leases to Lessee, and Lessee hereby hires and leases from Lessor, the exclusive right, upon the terms and conditions hereinafter set out, to inject and store natural gas in and withdraw and remove natural gas from the Winters Zone (located approximately between the depths of 3,500 feet and 4,000 feet beneath the surface) underlying the surface of the lands described in Exhibit A attached hereto and made a part hereof ("Property"), said formations and horizons being hereinafter referred to as "Storage Reservoir," together with all rights incident to said injection, storage, withdrawal and removal, including without limitation the following:

a. The right to use the Storage Reservoir as an Underground Gas Storage Reservoir, to use, produce or sell any currently producible gas or other hydrocarbons within the Storage Reservoir, and to store and remove natural gas in the Storage Reservoir and retain possession and ownership of any such natural gas so stored as personal property.

D2-266

2. Signing Bonus, Rent, and Possible Royalty for Any Currently Existing Commercially Producible Native Gas. Lessee shall pay to Lessor the following:

a. Signing Bonus. Upon execution and delivery of this Agreement by Lessor to Lessee, if done before Lessee is issued a Certificate of Public Convenience and Necessity ("CPCN") as a Gas Corporation by the California Public Utilities Commission ("CPUC") Lessee shall pay to Lessor a signing bonus calculated at the rate of $1,000.00 per acre (or fraction thereof) of Lessor's Property (or a minimum signing bonus of $500.00 for Property of less than one-half (1/2) acre).

b. Rent. Upon the earlier of March 31, 2010 or sixty (60) days after Lessee has both (i) received a CPCN from the CPUC and the CPCN has become final and (ii) Lessee has commenced the injection of third party gas for storage (the "Rental Commencement Date") Lessee shall pay to Lessor as "Rent" the greater of:

(1) An advance "Annual Minimum Rent" in the amount of $1,000.00 per acre of Lessor's Property (or $500.00 for Property of less than one-half (1/2) acre). The Annual Minimum Rent shall be increased at the end of each year following the Rental Commencement Date by four percent (4%); and

(2) If greater than the applicable Annual Minimum Rent, to be determined and paid within sixty (60) days of each anniversary of the Rental Commencement Date, "Percentage Rent" in the amount of four percent (4%) of actual annual gross

income from the conduct of gas storage operations for the just ended year, times a fraction, the numerator of which shall be the gross surface area of Lessor's Property expressed in acres (which is _____ acres), and the denominator of which shall be the gross surface area of Lessee's gas storage project expressed in acres (which total acreage shall be determined by Lessee upon receipt of final engineering data and stated in a written notice to Lessor, but shall not be more than 300 acres. Such determination of total acreage need not be based on a precise survey of the exterior boundaries of Lessee's gas storage project but may be estimated by Lessee.). Gross income from the conduct of gas storage operations shall include both capacity and usage charges paid by gas storage customers, but shall not include the proceeds of sale of all or any portion of the gas storage project or the proceeds of any project finance or other loan for such project, or the value of any gas utilized as fuel for operations

c. If Lessor is the owner of oil, gas and other hydrocarbon rights in the Property (if such rights were not reserved by a prior owner of the Property or separately conveyed away from surface ownership of the Property, as determined in the course of Lessee's title examination), Lessee shall pay to Lessor a "Royalty" to the extent that Lessee produces for use or sale any currently existing commercially producible native natural gas from the Storage Reservoir, determined as follows:

(1) If Lessee, at the end of each fifth anniversary of the Rental Commencement Date has withdrawn a quantity of natural gas from the Storage Reservoir in excess by more than 7/10ths of one percent (0.7%) of the quantity of natural gas injected into the Storage Reservoir (presumed to be "Native Gas"), Lessee shall pay to Lessor the following Royalty:

a. A fraction, determined by dividing the acreage of the Property covered by this Agreement by the total acreage covered by this Agreement and all underground gas storage agreements overlying the Storage Reservoir, of one-sixth (1/6th) of the value of Native Gas withdrawn from the Storage Reservoir, proportionately reduced to the percentage of oil and gas mineral rights in the Property owned by Lessor if less than 100% ownership.

b. The quantities of gas withdrawn and injected shall be adjusted for water content. The value of Native Gas so withdrawn shall be determined on the basis of the price paid on each applicable fifth anniversary of the Rental Commencement Date by Pacific Gas and Electric Company ("PG&E") at the wellhead for gas of similar quality in Northern California. If on that date PG&E is not purchasing natural gas for resale in Northern California the value shall be the price set forth in Natural Gas Intelligence, "Monthly Contract Index," under "PG&E City gate," minus the then current firm transportation rate for PG&E "Silverado" backbone transportation capacity, including fuel, published in the month of such expiration or termination of this Agreement.

D2-266 (Cont.)

3. This Storage Agreement shall continue for a term of thirty-three (33) years from and after the Rental Commencement Date and so long as the Storage Reservoir is used for underground storage of natural gas or the removal or injection thereof with no continuous period of non-use of two (2) consecutive years. The term "non-use" as used in this paragraph shall mean both no injection of gas into and no withdrawal of gas from the Storage Reservoir. Non-use shall not be deemed to have occurred if there was either injection of gas into or withdrawal of gas from the Storage Reservoir within the relevant period. Nothing in this paragraph or Storage Agreement shall obligate or require Lessee to use or continue to use the Storage Reservoir. Lessee shall notify Lessor in writing of the existence of any continuous period of non-use of two (2) or more consecutive years.

Lessee shall be entitled to extend this Storage Agreement, successively, for up to two (2) additional thirty three (33) year terms upon the same terms and conditions set forth herein, except that there shall be no further option to extend, by delivering written notice of its intent to extend to Lessor not sooner than one (1) year and not later than three (3) months prior to expiration of the then existing term hereof.

4. Lessee shall defend, indemnify and hold harmless Lessor, its officers, employees, governing body members, and agents from and against any and all claims, demands, losses, damages, liabilities, fines, charges, penalties, administrative and judicial proceedings and orders, judgments, remedial actions of any kind, and all costs and expenses incurred therewith, including without limitation, reasonable attorneys' fees and costs of defense arising, directly or indirectly, in whole or in part, out of Lessee's activities or facilities or improvements installed by the Lessee, for any reason whatsoever and without limitation, except to the extent arising from or caused by the intentional or willful misconduct or sole negligence of the Lessor, its officers, employees and agents.

5. Prior to the commencement of gas storage operations and thereafter so long as this Storage Agreement is in effect, Lessee shall place in effect and maintain Commercial General Liability insurance with a combined single limit of at least Ten Million Dollars ($10,000,000.00) each occurrence covering the Project. An umbrella liability policy or policies may be used to obtain the total limit. All insurance companies issuing the required insurance shall have a Best's rating of A-XII or better.

6. If and to the extent that ad valorem real property taxes assessed against the Property (including without limitation any taxes assessed against the minerals or base gas value) are increased as a result of Lessee's use of the Property Lessee shall be responsible for payment thereof. Lessee shall be responsible for payment of any personal property taxes assessed against the personal property of Lessee installed thereunder, which shall be billed separately from any taxes assessed against the real property of Lessor.

7. All payments provided for herein, following the initial payment referred to herein, may be made by check mailed directly to Lessor at the address set forth in Paragraph 14 hereof and in the percentages set forth opposite Lessors' signatures hereto.

If at any time there be as many as four (4) parties entitled to any payments from Lessee hereunder, Lessee may withhold payment thereof unless and until all such parties designate, in writing to Lessee, a common agent to receive all payments due hereunder.

D2-266 (Cont.)

8. If the Lessor owns a less interest in the Storage Reservoir than the entire and undivided fee simple estate therein, then the various payments referred to in this Storage Agreement shall be proportionately reduced.

9. Lessee, at its option, may at any time quitclaim and surrender all of the Property and Storage Reservoir, or any portion thereof, to the Lessor in which event this Storage Agreement shall be at an end as to that portion of the Property and Storage Reservoir so surrendered and quitclaimed, and Lessee shall be relieved of all obligations thereunder except the obligations then accrued.

10. Performance of the covenants and conditions imposed upon Lessee hereunder shall be excused while, and to the extent that, Lessee is hindered in or prevented from complying therewith, in whole or in part, by war, riots, strikes, walkouts, action of the elements, laws, rules, and regulations of any federal, state, municipal or other governmental agency or any other cause beyond the control of the Lessee, whether similar or dissimilar to those herein specifically enumerated without regard to whether such cause exists at the date hereof or hereafter arises; provided, however, that Lessee shall provide written notice to Lessor of any claim of suspension or excuse of Lessee's obligations under this paragraph, specifying with particularity the act, event, or condition giving rise to such claim of suspension or excuse and specifying the date on which such act, event, or condition arose.

11. Lessor hereby warrants and agrees to defend the title to the Property and Storage Reservoir and should Lessor hereafter acquire any additional right, title, or interest in or to the Storage Reservoir or Property, it shall be subject to the provisions hereof to the same extent as if owned by Lessor at the date hereof. Lessor agrees that the Lessee shall have the right at any time to redeem for the Lessor, by payment, any trust deed, mortgage, taxes, or other liens on said land, in the event of default of payment by the Lessor, and shall be subrogated to the rights of the holder thereof; and Lessor agrees that any such payments made by the Lessee shall be deducted from any amounts of money which may become due the Lessor under the terms of this Storage Agreement. Lessor warrants to Lessee that the Property is not subject to any lease which would interfere with the exercise of Lessee's rights hereunder, whether of record or not, except as set forth in Exhibit "C".

12. To the extent that the Lessor owns any right, title, or interests in and to the minerals underlying the Property, Lessor hereby consents to commingling of stored gas with any remaining native gas which may exist within the Storage Reservoir.

13. Should Lessor claim that a default has been made by Lessee in the payment of any sum due hereunder to Lessor or in the performance of any other term or condition hereof, Lessor shall provide written notice thereof to Lessee. If such claimed default is not contested or cured by Lessee within a period of thirty (30) days following Lessee's receipt of Lessor's written notice thereof, or, if such default is not curable within such 30-day period, if Lessee has not either contested or commenced the cure of such default within such 30-day period and diligently prosecutes such cure to completion, Lessor may declare this Lease and Agreement terminated and may pursue any and all remedies available at law or in equity.

14. This Storage Agreement shall extend to and be binding upon the heirs, assigns, executors, administrators, personal representatives, and successors of the parties hereto, and either party may assign, transfer, and convey, either in whole or in part, its ownership or interest in the land, rights, privileges, and property covered by this Storage Agreement; but no change in ownership of the Property shall be binding upon the Lessee until the instrument conveying title thereto shall have been properly recorded in the Official County Records and a certified copy thereof shall have been furnished to the Lessee.

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(Cont.)

15. Any notices or requests herein required or permitted shall be deemed sufficient as to delivery if given in writing, deposited in the United States mails, registered, return receipt requested, addressed to the other party hereto as follows:

LESSOR: _____
_____
_____

LESSEE: Sacramento Natural Gas Storage, LLC
2981 Gold Canal Drive
Rancho Cordova, CA 95670

16. Lessee shall comply with any and all terms and conditions (including without limitation any mitigation measures) set forth in any Certificate of Public Convenience and Necessity issued by the California Public Utilities Commission ("CPUC") for operation of the Storage Reservoir as a gas storage facility. Lessee shall not be considered to not be in compliance with any such term or condition unless found not to be in compliance by final action of the CPUC or a court with jurisdiction thereon, and shall be afforded a period of thirty (30) days to commence and thereafter diligently prosecute actions to remedy such non-compliance prior to being in default under this Agreement.

17. Drilling through the Winters Zone could adversely affect the integrity of the natural gas storage reservoir in the Property to be utilized by Lessee in its storage and withdrawal operations. In consideration of the foregoing, Lessor, to the extent Lessor may be a mineral owner, agrees not to drill through or into or grant others the right to drill through or into the Winters Zone, without Lessee's prior written consent. Lessee will not withhold its consent unless the proposed operations could potentially damage or drain the storage reservoirs in the Winters Zone and any proposed lease or agreement therefor does not contain protective measures and indemnifications that in Lessee's reasonable judgment protect Lessee from damage or loss. Should a dispute arise as to the reasonableness of any withholding of consent to drill by Lessee, such dispute shall be resolved by arbitration in the manner set forth in Paragraph 18 hereof.

18. Any disputes between the parties to the Agreement as to the interpretation or enforcement thereof shall first be attempted to be resolved by mediation before a mediator to be appointed by JAMS, the costs and expenses of which shall be shared equally by the parties. Should the dispute not be resolved by such mediation within a period of thirty (30) days following appointment of the mediator, either party may by giving written notice of intent to arbitrate to the other party require the dispute to be resolved by arbitration before a single arbitrator as may be mutually agreed upon in writing to the parties hereto within a period of ten (10) days of either party's receipt of a notice to arbitrate from the other should the parties fail to agree upon a single arbitrator within such period the arbitrator shall be appointed by the San Francisco Office of the American Arbitration Association. The decision of the arbitrator shall be binding on the parties hereto. The fees and costs of the arbitrator and the attorneys fees of the party prevailing in such arbitration shall be determined and ordered paid by the losing party to the prevailing party in the arbitration award. Except as otherwise expressly provided herein, such arbitration shall be conducted in accordance with the complex commercial arbitration rules of the American Arbitration Association.

19. This Agreement, its validity, construction and all rights under it shall be governed by the laws of the State of California with venue in Sacramento County.

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(Cont.)

20. Covenants for Lender's Benefit. Lessee may at any time assign, sublicense, sublease, or transfer to any lenders, banks or other commercial transferees (herein, "Lenders") or assign or transfer to a Trustee a deed of trust for the benefit of any Lender or an agent for Lenders ("Agent") all or any part of Lessee's interest under this Storage Agreement without the consent of Lessor. Lessee shall give written notice to Lessor of any such assignment, sublease or transfer, and of any further assignment by any such Lender or Agent, providing in each case the name and address of such Lender or Agent. Should Lessee assign, sublicense, sublease, or transfer any of its interest as provided above, Lessee and Lessor expressly agree between themselves and for the benefit of any Lenders or Agent for Lenders as follows:

a. Lessor shall promptly deliver to Lenders or Agent a copy of any notice of default hereunder sent to the Lessee under the Storage Agreement and agrees that any notice to the Lessee of any default or intention by the Lessor to terminate the Storage Agreement shall not be effective against the Lenders or Agent unless Lessor shall have given to Lenders or Agent notice of such default or termination. Any such notice (a "notice") to the Lenders or Agent shall be in writing, shall be addressed to Lenders or Agent at their address designated in writing by notice to Lessor and shall be deemed given or made upon the third business day following deposit thereof in the mail, postage prepaid. The Lenders or Agent may by notice to the Lessor change the address to which such notices, demands, requests or other communication shall be given.

b. Lessor shall not exercise any right, power or remedy under the Storage Agreement and under no circumstances shall the Lessor terminate the Storage Agreement, if: (i) in the event of a default in the payment of rent or other sum due under the Lease, the Lenders or Agent pay or cause to be paid such rent or other sum within 30 days after receipt of notice from the Lessor; or (ii) in the event of any default other than the payment of rent or other sum due under the Storage Agreement, the Lenders or Agent shall cure or cause to be cured the default within 60 days after receipt of notice from the Lessor or, if such default is not susceptible of being cured within 60 days, the Lenders or Agent have commenced steps necessary to cure the default and proceed diligently to cure the default.

c. If the Storage Agreement and Lessee's leasehold interest in the Property is sold, assigned or transferred to the Lenders or Agent pursuant to the exercise of any right, power or remedy reserved to the Lenders or Agent under a credit agreement or deed of trust, the Lenders or Agent shall have the right to assign the Storage Agreement without the Lessor's consent and upon such assignment the Lenders and Agent, if any, shall be released from the performance of all obligations of the Lessee under the Storage Agreement.

d. If the Storage Agreement is terminated for any reason whatsoever, other than a termination by reason of Lender's or Agent's failure to cure a default which is susceptible of being cured pursuant to Paragraphs 13. and 20.b. hereof, the Lessor shall, upon the request of the Lenders or Agent, immediately recognize the Lenders or Agent or their or its nominee, purchaser, assignee or transferee as the Lessee under the Storage Agreement for the remainder of the term of the Storage Agreement and, in such event, the Lenders or Agent or their or its nominee, purchaser, assignee, or transferee shall be automatically substituted as the Lessee under the Storage Agreement.

e. Lessor shall not consent to any modifications or amendments of the Storage Agreement without the consent of the Lenders or Agent.

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(Cont.)

f. Lessor certifies as of the date above first written and thereafter, in accordance with Paragraph 20.g. hereof, that (i) the Storage Agreement is currently in full force and effect and has not been modified, amended or revoked, and (ii) no default, or event which with the giving of notice or the passage of time, or both, would constitute a default under the Storage Agreement has occurred and is continuing.

g. Lessee and/or Lenders or Agent shall have the right from time to time to deliver to Lessor in accordance with Paragraph 15. of this Storage Agreement, a written request ("Written Request") that Lessor confirm to Lenders or Agent (at the address set forth in such Written Request) the certifications contained in Paragraph 20.f. herein or, alternatively, inform Agent of any exceptions that have arisen with respect to the certifications contained in Paragraph 20.f. herein. Should Lessor fail to respond within ten (10) days of its receipt of such Written Request, Lessor (i) shall be deemed to have made the certifications contained in Paragraph 20.f. of this Storage Agreement as of the date of such Written Request and (ii) shall be estopped from claiming that any default or breach has occurred under the Storage Agreement on or prior to the date of such Written Request.

21. Lessor Escape Clause. Lessee agrees that it will not record a memorandum of this Agreement prior to the morning of the seventh (7th) business day after the effective date hereof. Lessor may cancel and render this Agreement void and of no effect, provided that Lessor has not negotiated the bonus check provided for in Paragraph 2 hereof, by written notice to Lessee so advising Lessee, mailed in accordance with Paragraph 15 hereof, postmarked not later than the third (3rd) day after the effective date hereof and actually received by Lessee not later than the sixth (6th) business day following the effective date hereof, and enclosing Lessor's bonus check. The recording of a memorandum of this Agreement at any time from and after the morning of the seventh (7th) business day after the effective date hereof shall be conclusive evidence that Lessor has not so cancelled this Agreement.

LESSEE:

SACRAMENTO NATURAL GAS STORAGE, LLC

By: _____ Date: _____

LESSOR:

See Lessor Signature Page Attached hereto and made a part hereof

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(Cont.)

ATTACHED TO AND MADE A PART OF THAT CERTAIN SUBSURFACE UNDERGROUND GAS STORAGE LEASE AND AGREEMENT DATED THE _____ DAY OF _____, 200__, BY AND BETWEEN _____, AS LESSOR AND SACRAMENTO NATURAL GAS STORAGE, LLC, A CALIFORNIA LIMITED LIABILITY COMPANY, AS LESSEE.

LESSOR SIGNATURE PAGE

LESSOR **INTEREST**

____%

By: _____ Date: _____

By: _____ Date: _____

Tax ID#: _____

____%

By: _____ Date: _____

Tax ID#: _____

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EXHIBIT J

SACRAMENTO
Natural Gas Storage

COMMUNITY FOUNDATION

What is the mission of the proposed Community Foundation?

- The Community Foundation is proposed by SNGS to receive an amount equal to 0.25% of annual gross revenues representing $25,000 to $44,000 or more per year.

- Monies donated would be used to support projects and activities that are favored by the community.

- Foundation Board of Directors to be established with representatives of local community groups such as AGENA and the Power Inn Alliance, the City, youth groups, a SNGS representative, etc., as members.

- The City of Sacramento's non-profit entity, "Gifts to Share, Inc.", to collect and distribute these dollars as determined by the directors.



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EXHIBIT K

SACRAMENTO
Natural Gas Storage

March 3, 2008

Matt Kelly
Sacramento-Sierra's Building and Construction Trades Council
2840 El Centro Road, Suite 107
Sacramento, CA 95833

Dear Mr. Kelly:

This letter sets forth the terms of a Project Stabilization Agreement ("Agreement") for the Project described below.

Project

Sacramento Natural Gas Storage, LLC ("SNGS") is currently proposing to construct facilities associated with storing natural gas in a depleted natural gas field in the Florin/Power Inn area of the City of Sacramento. Facilities proposed to be constructed include a well pad for injecting and withdrawing natural gas stored in the gas field; a compressor station for compressing, drying, metering and controlling the gas; and associated pipelines. This project ("Project") is described in the SNGS Project Spring Summer Newsletter (Attachment "A" hereto). The Project is more completely described in an application made April 9, 2007 by SNGS to the California Public Utilities Commission for a Certificate of Public Convenience and Necessity which has been amended to propose an interconnect to PG&E in West Sacramento.

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Parties to the Project Stabilization Agreement

The parties to this Agreement are:

1. SNGS, the owner of the Project;

2. Exterran Energy Solutions, L.P. or its affiliate, the company responsible for engineering, designing and fabricating the compressor units and associated equipment, and installing and starting up these units ("Exterran");

3. Performance Mechanical Inc., the contractor responsible for on-site construction of buildings and facilities, excluding work within the scope of Exterran's responsibilities;

4. ARB Inc., or such other contractor as may become responsible for construction of the pipelines ("ARB");

5. Sacramento-Sierra's Building and Construction Trades Council ("Council"); and

6. Local unions affiliated with the Council.

Covered Work

The work covered by this Agreement ("Covered Work") is that work which will be performed by Performance Mechanical Inc. (or any contractor which may be a successor to Performance Mechanical Inc.), ARB (or any contractor which may be a successor to ARB), and their respective subcontractors, namely, all on-site work involved in the construction of the Project, except for the exclusions below.

Exclusions

1. Work to be performed by Exterran pursuant to its responsibilities for engineering, designing, fabricating and start up of the equipment and units necessary for natural gas storage, and overseeing the installation of these units [including without limitation compression units, natural gas production, dehydration and separation equipment, specialized controls equipment and instrumentation, and other necessary equipment];

2. Work to be performed by Exterran of an ongoing maintenance or operational nature that extends beyond the initial engineering, design and fabrication of the work described in Paragraph 1 hereof;

3. Warranty or remedial repairs to be performed by Exterran following the expiration of this Agreement;

4. Work to be performed by specialized contractors to complete technical, quality inspection, or installation work when required by an equipment manufacturer in order to maintain a warranty or for well drilling activities;

5. Work not directly related to the on-site construction, including but not limited to landscaping;

6. Work to be performed by nonunion subcontractors in the event the Council cannot supply qualified union subcontractors, which are ready and able to timely start work on the project. The Council shall work with Performance Mechanical, Inc. and/or ARB to ensure qualified subcontractors are in a position to submit proposals for work on all aspects of the project (except as excluded in items 1-5 above and item 7 below). In the event that bids from qualified subcontractors are not presented, Performance Mechanical, Inc. and/or ARB may at its discretion reopen the bid on the portion of the work in question so long as this process does not delay the project. The determination of whether a subcontractor is qualified shall be made by Performance Mechanical Inc. as to its work and ARB for the pipelines, in consultation with the Council;

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(Cont.)

7. Work to be performed by executives, engineers, draftsmen, managers, inspectors, technicians, project managers, accountants, supervisors, surveyors, timekeepers, messengers, office workers, guards, quality control and quality assurance personnel, or other non-manual employees.

Use of Union Trades People

SNGS, Performance Mechanical, Inc. and ABR will perform all Covered Work associated with the Project utilizing trades people dispatched by local unions affiliated with the Council subject to the foregoing Exclusions.

Terms of Employment of Employees Performing Covered Work

The wages and fringe benefits for the employees of Union subcontractors performing Covered Work shall be consistent with the Local Union's collective bargaining agreements for each applicable craft, which are in effect for the duration of this Agreement. This includes any fringe benefits increases that become effective under the collective bargaining agreements.

Union subcontractors of Performance Mechanical Inc. and ARB shall be signatory to the appropriate collective bargaining agreements for the crafts signatory to this Agreement and affiliated with the Council. Performance Mechanical Inc. shall be responsible for conveying the terms and conditions of this Agreement to its subcontrators.

If it becomes necessary to utilize non-union subcontractors consistent with the terms of this Agreement, the wages and benefits of such non-union subcontractors will not be governed by this Agreement or the Local Union's collective bargaining agreements.

No Strikes, Lockouts, or other Economic Action

1. There shall be no strikes, work stoppages or slowdowns, or any other disruptive activity affecting the normal progression of the job for any reason whatsoever during the term of the Agreement. Jurisdictional or "scope of work" disputes among signatory unions shall be resolved by the Council in a manner that does not disrupt or delay the pace of construction for any reason whatsoever. The Council and affiliated unions will not recognize job actions, pickets or protests of unions not affiliated with the Council. If such prohibited activities take place, the unions shall immediately take all reasonable and necessary action to end such activities. In addition, unions that are signatory to this Agreement shall not honor picket lines established by non-signatory unions, or in any way assist organizing activity of other non-signatory parties to this Agreement. In the event of any strike, slowdown, or work stoppage of any type occurs, the parties will resolve the dispute by expedited arbitration proceedings in accordance with the arbitration provisions below.

2. There shall be no lockouts by Performance Mechanical Inc. or ARB or by any subcontractor at any tier. In the event a lockout occurs, the parties will resolve the

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dispute by expedited arbitration proceedings in accordance with the arbitration provisions below.

Resolution of Disputes and Arbitration

1. In the event of any dispute among the parties to this Agreement that cannot be informally resolved, the dispute will be resolved by binding, expedited arbitration. Mutually agreeable candidates to serve as arbitrators include: Tom Angelo, William Riker and John Kagel. When any party alleges a breach of the no strikes, lockouts or other economic action provisions above, or any other provision of the Agreement that could adversely affect the progress of construction on the Project, the parties shall notify one of the three arbitrators identified above. If none of the three arbitrators are available, a selection method is set forth below. Upon receiving notice, the Arbitrator shall hold a hearing within twenty-four (24) hours. The arbitrator shall issue a written decision within three (3) hours after the close of the hearing. If the arbitrator determines the union has violated the Agreement, the union shall, within eight (8) hours of issuance of the arbitrator's decision, direct all represented employees to immediately return to work and/or cease the activity violating the Agreement. If the arbitrator determines that a lockout has occurred in violation of the Agreement, the party initiating the lockout shall, within eight (8) hours, confirm that the lockout has ended. The arbitrator's decision and award shall be final and binding on all parties and may be enforced in any court of competent jurisdiction. The expense of arbitration, including the cost of the arbitrator, shall be borne solely by the losing party.

2. If none of the mutually agreeable arbitrators is available, an arbitrator shall be selected by the following process: the party seeking arbitration shall request a list of seven (7) potential arbitrators from the American Arbitration Association ("AAA") with construction labor experience. The parties shall first attempt to mutually agree on an arbitrator from this list. If the parties cannot agree, the parties shall alternatively strike one name from the list until the parties agree on an arbitrator or until only one name remains. The party seeking arbitration shall strike a name first. The parties will not unnecessarily delay these proceedings and agree to complete the arbitrator selection process by the conclusion of the business day immediately following the date on which the AAA provides the list of seven potential arbitrators. The parties agree that time is of the essence and agree to use their best efforts in good faith to select an arbitrator.

Non-Compliance with the Terms of this Agreement

In the event the Council does not comply with the terms of this Agreement, then SNGS, Exterran and/or Performance Mechanical Inc. or ARB may within a period of forty-eight (48) hours, at their sole discretion, employ any contractor or subcontractor that it deems qualified to perform work on the jobsite notwithstanding the terms of this Agreement. Before taking this action, all efforts to resolve the dispute – including the arbitration process outlined above, must be exhausted. In the event the Council believes any of the other parties are out of compliance with this Agreement, the Council shall likewise exhaust the arbitration process outlined above.

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Miscellaneous Provisions

1. This Agreement envisions a preference to employ local workers on the job, and outreach efforts to employ minority workers and subcontractors. In the awarding of work, preference shall be given to contractors already employed on the job and performing satisfactorily, all with respect to Covered Work.

2. All parties recognize that it is essential to enhance productivity in the field of private building construction work. To this end, the Council agrees to give this Project the highest priority.

3. The Council shall develop information, inform its members and generally work to explain the overall benefits of the project to its membership and other interested parties.

4. The parties shall work together to develop materials that explain the substantial economic and job-related benefits of this Project to the greater Sacramento community and political bodies.

5. No travel or subsistence payments are envisioned except as specifically provided in this Agreement.

6. Other terms and conditions of employment applicable to employees hired to perform Covered Work shall be governed by the applicable collective bargaining agreements of the affected craft Locals affiliated with the Council. In addition, the parties agree that: (1) all workers shall wear presentable and non-offensive attire and safety equipment appropriate and necessary to their trade; and (2) all contractors and subcontractors will enforce a drug-free workplace and will implement a drug testing policy on the Project.

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Expiration of this Agreement

This Agreement shall expire when construction of the Project is completed, which is defined as the earlier of (i) sixty (60) days following Mechanical Completion of the Project; or (ii) the date on which SNGS signs the "Final Acceptance Certificate."

Severability and Entire Agreement

If any part of this Agreement is found to be in violation of any state, federal or local law or regulation, that part of the Agreement shall not be applicable, but the remainder of the Agreement shall continue in full force and effect.

This Agreement contains the entire agreement of the parties with respect to the matters covered herein, and supercedes any prior oral or written understandings or agreements with respect to the same matters.

Counterparts

This Agreement may be executed in two or more counterparts all of which when taken together shall constitute one and the same document. The signature of any party to any counterpart shall be deemed a signature to, and may be appended to, any other counterpart.

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(Cont.)

This Agreement is entered into this date: _____

Signatory Parties:

SACRAMENTO NATURAL GAS STORAGE, LLC

By: _____
Name/Title: Jim Fossum, Chairman

EXTERRAN ENERGY SOLUTIONS, L.P. or its affiliate.

VHB

By: _____
Name/Title: VP Total Solutions

PERFORMANCE MECHANICAL INC.

By: _____
Name/Title: V.P. Operations
DAVID QUIRIC

ARB INC.

By: _____
Name/Title: Donald K Brown VP

SACRAMENTO-SIERRA'S BUILDING AND CONSTRUCTION TRADES COUNCIL

By: _____
Name/Title: Business Mgr.

APPENDIX 13

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

DIRECT TESTIMONY OF

DONALD B. RUSSELL

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail: ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: September 5, 2008

Q1 ***Describe Your Educational Background.***

After graduating from high school, I went on to attend and graduate from Virginia Polytechnic Institute (now known as Virginia Tech) with a Bachelor of Science degree in Industrial Engineering. I then attended the Georgia Institute of Technology, where I pursued a Master of Science degree from the School of Industrial and Systems Engineering. I was called to active duty in the military service before completing all of the MS degree requirements.

Q2 ***Describe Your Work Experience Prior To Working In The Energy Industry.***

I spent about seven years in the US Air Force, working as a Health Facilities Officer, for the Office of the Air Force Surgeon General. The Health Facilities Division provided design and construction management services on medical centers, hospitals, clinics, and dental clinics, worldwide. My final assignment for the Department of Defense was serving as the Chief of Facilities for the Uniformed Services University of the Health Sciences (USUHS) in Bethesda, Maryland. The University was under construction at that time.

Upon leaving the federal service, I moved to Saudi Arabia for about two years, where I served as the Chief of Design and Construction on the King Faisal University, which included a College of Medicine. I was employed by University Associates for International Health, a non-profit corporation. I then went to work for CM, Inc., of Houston, Texas, one of the two largest construction management companies in the world, at that time. My first year was spent based in London, doing international marketing for the firm throughout the Middle East. I then returned to the United States to help establish the first construction management contract ever entered into by the State of California. I then went on to serve as Officer in Charge of the company's first west coast office, based in Los Angeles.

I left CM, Inc., in 1981, to establish a new construction management firm, Vanir Construction Management, Inc. I became a member of the Board of Directors, and served as President until 1993. The firm is headquartered in Sacramento. I continue to serve on its Board of Directors.

Q3 ***Describe Your Work Experience In The Energy Industry.***

In 1994, I changed the focus of my career and entered the natural gas sector of the energy industry, working for Tejas Power Company, in Houston, Texas. I helped establish a partnership of utilities, known as Market Hub Partners. Over the next four years, while I served as President of MHP, the Company became the largest developer/owner/operator of independent (market-based rate) natural gas storage facilities in the country. The company worked on the development of a depleted reservoir storage facility (which eventually became known as the "Lodi Project," in Lodi, CA), and four salt cavern, natural gas storage facilities, two of which were in full operation by the time MHP was acquired by one of the original partners. I was intimately involved in all aspects of developing these projects, including the geology, engineering design and operation of these facilities. I believe this experience brought me extensive knowledge and expertise in such matters, which I have applied to this project.

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In 2000-2004, I helped establish and operate a new partnership known as SG Resources, LLC, to develop/own/operate natural gas storage facilities in the Gulf Coast area of the United States. In this role, I worked on the development of three natural gas storage facilities, two of which are under development, and one of which is in operation. This work further utilized and enhanced the natural gas storage expertise which I developed at MHP.

In 2006, I participated as one of the originators of Sacramento Natural Gas Storage, LLC. This company was formed to develop an underground natural gas storage project to serve the needs of the Sacramento area, utilizing a naturally-occurring depleted natural gas reservoir. I was designated as President of the company and currently serve in that capacity.

Q4 ***Describe Your Involvement With The Lodi Natural Gas Storage Facility.***

In 1992, I became a member of a company that was formed to develop an underground natural gas storage facility in the Sacramento area. The company was formed primarily to respond to a Request for Proposals, issued by the Sacramento Municipal Utility District (SMUD), to develop an underground natural gas storage facility to serve SMUD's needs. The project the company was proposing to develop eventually became known as "the Lodi project", which is in operation today. Although SMUD never took action on the proposals to develop the project, the company continued to attempt its development. About 1996, while I was serving as President of Market Hub Partners in Houston, MHP acquired the development rights for the Lodi project from the then-current owner. For internal reasons, the MHP Board of Directors elected not to pursue the development of the Lodi project. The development rights were subsequently sold to another company, after which I had no further involvement with the project.

Q5 ***Describe Your Experience With Jim Fossum, Prior To The Establishment Of SNGS.***

I first met Jim Fossum in 1979, when he was the Executive Director of Sonoma State Hospital. Jim was a primary "owners rep" for a construction program management contract to renovate 10 State Hospitals. I was serving as the Officer in Charge of the CM team. We enjoyed a solid and successful "owner/client" relationship during the three-year period of that contract. We also developed a strong friendship.

Jim and I maintained our friendship after he left the State service and engaged himself in the natural gas industry, sometime in the mid-1980's. When I moved back to Sacramento in 2004, Jim and I started discussing potential underground natural gas storage projects that he had identified. Our discussions continued intermittently until 2006, when we decided to establish SNGS.

Q6 ***Are You An Investor In SNGS?***

I am currently an investor in a limited liability company that owns equity in SNGS.

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Q7 ***Describe The Different Roles That You And Jim Fossum Play As President And Chairman, Respectively.***

We work closely together on all aspects of the project development process. Jim takes the lead on matters involving investor relations, real estate and property rights, community outreach, general administrative duties, and personnel matters. I take the lead on engineering and design issues, permitting and entitlements, financing and budgetary issues.

Q8 ***In Carrying Out Your Responsibilities For Financing And Budgetary Issues, Have You Considered The Cost Of Obtaining General Liability And Other Forms Of Insurance For This Project?***

Yes.

Q9 ***Has SNGS Obtained Estimates From Insurance Brokers For The Cost Of Obtaining Various Forms Of Insurance For The Project?***

Yes.

Q10 ***Please Generally Describe The Types Of Insurance Coverage For Which SNGS Has Obtained Cost Estimates.***

SNGS has obtained quotations from Bart LeFevre, a highly qualified and knowledgeable petroleum industry insurance broker, for general liability coverage, product in storage, umbrella coverage, well control, surface equipment, and business insurance, among others. A description of Mr. LeFevre's work experience is included in the document attached as **Exhibit A**.

Q11 ***Please State The Policy Limits For Which You Have Obtained Estimates For General Liability And Umbrella Coverage.***

Our broker has advised us that we can likely obtain general liability coverage with a $2,000,000.00 policy limit with an annual premium of approximately $50,000.00, and $50,000,000.00 in umbrella coverage with an additional annual premium of approximately $130,000.00.

Q12 ***Has Your Broker Advised You That He Can Secure Policies For Those Stated Amounts?***

Yes. Our broker has stated that he is confident that he can place these insurance policies for approximately $180,000.00, give or take approximately ten percent of the estimated annual premium amounts.

Q13 ***Did Your Broker Send You A Letter Confirming These Estimates?***

Yes.

Q14 ***Is A True And Correct Copy Of That Letter Attached As Exhibit B?***

Yes.

D2-269 (Cont.)

Q15 ***Does SNGS' Operational Budget Permit It To Spend Up To $200,000.00 Per Year For General Liability And Umbrella Coverage For The Policy Limits You Stated In Response To Question 11?***

Yes, it does. I am very confident that our operational budget can accommodate that expense, and I have included that amount as a line item in SNGS' operational budget.

Q16 ***Is SNGS Capable of Obtaining Liability Insurance Of Up To $50,000,000?***

Yes, Mr. LeFevre has assured SNGS that we can obtain insurance for that amount of coverage and he has informed me that limits of $50,000,000 should be sufficient for a project like ours.

Q17 ***Did You Investigate What Impact, If Any, The Bill Pending In The State Legislature (S.B. 1700), Which Would Impose Strict Liability On SNGS For This Project, Would Have On The Cost Of Obtaining Insurance?***

Yes, we did. According to our insurance broker, passage of Senate Bill 1700 would have no appreciable impact on (a) our ability to obtain insurance, or (b) the cost of obtaining the coverage limits discussed above.

Q18 ***Is SNGS Able And Willing To Provide Such Bonds And Indemnity As May Reasonably Be Required For This Project?***

Yes. My experience in the construction and natural gas industries is such that I can foresee the nature, amount and availability of performance and other bonds typically required for projects like ours. SNGS is ready, willing and able to provide all such bonds as may be required by the PUC, DOGGR and other agencies

The same holds true for third party indemnities. Indeed, SNGS already has provided broad form indemnities in its landowner storage rights agreements, its leasing agreement for the compressor station and in its agreement with SMUD

Q19 ***What, If Anything, Has SNGS Done To Make This An Environmentally-Conscious Project?***

SNGS elected to secure a LEED's certification for the project from the US Green Building Council and has become a member of the US Green Building Council. See the Membership Certificate attached hereto as **Exhibit C**. LEED's Certification has come to be recognized over the past decade as the most prominent and credible means to establish a project's commitment to energy conservation and sustainable operations, world-wide. SNGS is contracting with a LEED's Approved Professional (LEEDS AP) who is one of the premiere LEED's consultants in California, to assist and guide SNGS through the design process that will permit SNGS to achieve its current goal of LEED's Gold Certification. To the best of our knowledge, the SNGS project will be the first project of this type to achieve such a credential. The general consensus is that, upon achieving such a certification, the project will be recognized both nationally and internationally for this achievement.

D2-269 (Cont.)

Q20 ***Have You Compared The Landowner Compensation Proposed In The SNGS Offer ("Offer") With That Set Forth In Harold Bertholf's June 1, 2007 Appraisal ("Appraisal")?***

Yes. The Bertholf Appraisal calls for a minimum annual payment that has several step-ups plus an annual escalation factor. Then after a startup period of 8 years a percentage rental kicks in and the rental thereafter will be the minimum payment vs. four percent (4%) of annual gross revenues, whichever is greater. The total rental is allocated among the landowners on an acreage basis using 270 acres as the total land area. Thus, the owner of one full acre would receive 1/270th of the total rental payment. Further work since the appraisal has enlarged the total land area to approximately 287 acres.

In order to encourage early signups and for other reasons discussed below, SNGS has made an Offer which is more generous than the Appraisal in the following ways:

a. The SNGS Offer includes an initial signing bonus of $1,000/acre but not less than $500/parcel, which also includes the time until (a) the facility goes on line or (b) March 31, 2009, whichever is sooner. In contrast, the Appraisal does not include a signing bonus but does include $163/acre, per year in rental payments until the project goes on line.

b. The total minimum rental payments covered by the SNGS Offer are higher than the Appraisal.

c. The Appraisal calls for an 8 year ramp up period for rental payments. SNGS has eliminated that delay in the start of making full payments, and rather has chosen to make the full percentage rent start as soon as the facility goes on line instead of waiting for the 9th year as prescribed by the Appraisal. The importance of this is underlined by SNGS' belief that the first full operating year at Florin could generate a total percentage rent to all storage rights lessors (taken as a group) of $704,000 ($2,450±/acre) vs. the minimum of $270,000 ($1,000/acre) in the Offer.

d. Parcels smaller than .5 acre (most residential parcels approximate 0.18 to 0.2/acre) will be treated as 0.5 acres such that the signing bonus and the annual minimum rental for such parcels will be $500.

Further, using the information set forth in the Appraisal and based on a 287 acre surface area, I have calculated and prepared rental comparisons of the Offer with the fair market rentals set forth in the Appraisal for one acre and 0.20 of an acre. Those comparisons are provided in the two charts attached as **Exhibits D** and **E**.

Q21 ***Does The Foregoing Complete Your Direct Examination Testimony?***

Yes.

D2-269 (Cont.)

EXHIBIT A

Bart J. Le Fevre

As a founder and President of the Company, Bart J. Le Fevre will be in charge of overall company development executing the business growth strategy. In addition, he is responsible for marketing and production, account renewal retention and client development. He has worked in the insurance industry for over 15 years. He began his career as Senior Underwriter/Broker with LeFevre Int'l, Inc. headquartered in Houston, TX with a satellite company in Los Angeles, CA. He was selected to lead two start-up energy insurance offices for retail brokers expanding into the Houston energy insurance market. Bart continued his career in Houston as a producer employed in the Energy & Marine division at McGriff, Seibels & Williams, the largest US independent energy & marine broker prior to them being acquired in 2004. Most recently Bart filled the position as Director of Energy & Marine programs Complete Insurance, Inc. a leading California independent energy broker. Bart produced and serviced over $1mm in revenue in year 2006. He is well recognized and regarded as the insurance specialist by members of the California Independent Petroleum Association (CIPA).

Bart is a self-motivated individual with exceptional sales, management and networking skills. His determination to succeed is the intangible characteristic needed to see the Company's business plan from the initial start-up through complete development. Bart has a B.B.A. in Finance with an emphasis in insurance from Stephen F. Austin State University, in Nacogdoches, TX. Bart is married and is the proud father of two children.

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EXHIBIT B

SACRAMENTO
Natural Gas Storage

March 3, 2008

Matt Kelly
Sacramento-Sierra's Building and Construction Trades Council
2840 El Centro Road, Suite 107
Sacramento, CA 95833

Dear Mr. Kelly:

This letter sets forth the terms of a Project Stabilization Agreement ("Agreement") for the Project described below.

Project

Sacramento Natural Gas Storage, LLC ("SNGS") is currently proposing to construct facilities associated with storing natural gas in a depleted natural gas field in the Florin/Power Inn area of the City of Sacramento. Facilities proposed to be constructed include a well pad for injecting and withdrawing natural gas stored in the gas field; a compressor station for compressing, drying, metering and controlling the gas; and associated pipelines. This project ("Project") is described in the SNGS Project Spring Summer Newsletter (Attachment "A" hereto). The Project is more completely described in an application made April 9, 2007 by SNGS to the California Public Utilities Commission for a Certificate of Public Convenience and Necessity which has been amended to propose an interconnect to PG&E in West Sacramento.

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Parties to the Project Stabilization Agreement

The parties to this Agreement are:

1. SNGS, the owner of the Project;

2. Exterran Energy Solutions, L.P. or its affiliate, the company responsible for engineering, designing and fabricating the compressor units and associated equipment, and installing and starting up these units ("Exterran");

3. Performance Mechanical Inc., the contractor responsible for on-site construction of buildings and facilities, excluding work within the scope of Exterran's responsibilities;

4. ARB Inc., or such other contractor as may become responsible for construction of the pipelines ("ARB");

EXHIBIT C

CA DOI License 0G13559

August 20, 2008

Mr. Donald B. Russell
Sacramento Natural Gas Storage, LLC
8031 Fruitridge Road
Sacramento, CA 95820

Re: Underground Natural Gas Storage Facility Project
Location - Florin Field in Sacramento, CA

Dear Mr. Russell:

This letter will confirm that I have conducted extensive research to estimate the cost for obtaining various lines of insurance, including general commercial liability, product in storage, umbrella coverage, well control, surface equipment, and business insurance, among others, for SNGS' proposed natural gas storage facility at the Florin Field in Sacramento. With respect to the commercial general liability and umbrella coverage for the facility's operation, I obtained pricing information for policies with limits of $2,000,000.00 and up to $50,000,000.00, respectively.

Based on my discussions with underwriters and brokers across the country, I am reasonably confident that I can place general liability coverage with a $2,000,000.00 policy limit for an annual premium of approximately $50,000.00, and $50,000,000.00 in umbrella coverage with an additional annual premium of approximately $130,000.00. The exact pricing of these policies is subject to change based on market conditions, but I am confident that I can place these policies for annual premiums that are within ten percent, plus or minus, of these estimates. My confidence in this pricing information is based on my extensive experience placing insurance policies for the owners and operators of gas and oil fields, oil refineries, and other natural gas storage facilities, and my recent communications with other brokers and underwriters across the country.

You also asked me to evaluate whether the California Legislature's passage of S.B. 1700 would impede SNGS ability to place insurance for its facility or materially increase the cost of obtaining such insurance. I have reviewed the draft language of S.B. 1700 and understand that, if passed, it would impose strict liability on SNGS for losses resulting from its operation of the proposed facility. I canvassed many different brokers and underwriters who place insurance for these types of facilities to determine what impact, if any, S.B. 1700 would have on SNGS' ability to obtain insurance policies for the prices listed above. Based on my discussions with market participants, and based on my own experience, I do not believe S.B. 1700 would have a material impact on SNGS' ability to obtain the

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Commercial Global Insurance Services of California, LLC
31 Journey, Suite 120 • Aliso Viejo • California • 92656 T 949.600.7995 • F 949.600.7998

insurance policies described above for the amounts I have quoted you. In other words, I am reasonably confident that I can place policies for SGNS for the amounts listed above, even if S.B. 1700 is enacted.

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(Cont.)

Please let me know if you have any questions regarding these issues, or need additional information.

Sincerely,

Bart J. Lefevre
President

EXHIBIT D



U.S. Green Building Council

Sacramento Natural Gas Storage, LLC

MEMBER SINCE 2007

THE U.S. GREEN BUILDING COUNCIL IS THE NATION'S FOREMOST COALITION OF LEADERS WORKING TO TRANSFORM THE WAY BUILDINGS AND COMMUNITIES ARE DESIGNED, BUILT AND OPERATED, ENABLING AN ENVIRONMENTALLY AND SOCIALLY RESPONSIBLE, HEALTHY, AND PROSPEROUS ENVIRONMENT THAT IMPROVES THE QUALITY OF LIFE.

Chairman

S. Richard Fedrizzi, President, CEO and Founding Chairman

EXHIBIT E

SACRAMENTO
Natural Gas Storage

ANNUAL PAYMENTS FOR ONE-ACRE OF STORAGE RIGHTS

COMPARISON OF "APPRAISED FAIR MARKET VALUE" AND THE SNGS OFFER

	Appraised Fair Market Value	SNGS Offer
SIGNING BONUS	$-0-	$1,000/acre ($500 minimum)
$/ACRE/YEAR		
Year 1	$610	$2,450
Year 5	$720	$2,870
Year 10	$3,490	$3,490
Year 15	$4,250	$4,250
5 Year Total	$3,700	$14,290
10 Year Total	$19,870	$30,450
15 Year Total	$39,540	$50,120

Note: SNGS Offer is based on 4% of projected estimated annual Gross Revenue of $17.6 million in the first full year of operations (Year 1)

December 4, 2007

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APPENDIX 14

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

DIRECT TESTIMONY OF

ARTHUR GIMMY

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail: ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: September 5, 2008

Q1 ***What Are Your Qualifications?***

Arthur E. Gimmy, MAI is the president of Arthur Gimmy International, a firm currently employing seven appraisers, plus support staff, located in Corte Madera and Newport Beach, California. He started in the appraisal business in 1959 and received the MAI credential in 1965.

Mr. Gimmy has taught many appraisal courses during his career including ones at San Jose State, UCLA, University of Tampa, University of Connecticut and SMU, and he also has served on numerous local and national committees during his career, including The Appraisal Journal Editorial Board for 10 years.

Most notably, Mr. Gimmy has been an author, having published nearly fifty articles on a wide variety of appraisal topics, and authored various books in use by appraisal professionals. Those published by the Appraisal Institute or its predecessor, the American Institute of Real Estate Appraisers, include: Tennis Clubs and Racquet Sport Projects, 1978; Elderly Housing, 1988; Fitness, Racquet Sports and Spa Projects, 1989; Golf Courses and Country Clubs, 1992 and 2002; Healthcare Enterprises, 1996; Senior Housing: Looking Toward The Third Millennium, 1999; and The Business of Show Business: The Valuation of Movie Theaters (2000).

Mr. Gimmy has been a pioneer in the analysis of a variety of difficult, unique, or specialized properties and appraisal concepts. He has provided expert testimony in litigation matters involving very large and complex real estate and business issues since 1961.

His awards include the Professional Recognition Award in 1975 and 1978, and the highest honor, the George L. Schmutz Memorial Award from the Appraisal Institute in 1996 at the Chicago meetings. The award includes a plaque and an honorarium. The Schmutz Award was established in 1959 and is for "his special contribution to the advancement of appraisal knowledge." Mr. Gimmy has been appraising property in the Sacramento area for over 30 years, involving a wide variety of property types and issues and has testified as an expert witness in the Superior Court and Federal Court. A copy of his resume is attached hereto as **Exhibit A**.

Q2 ***What Is Your Appraisal Experience With Oil And Gas Properties?***

Arthur Gimmy International has been appraising a wide variety of oil and gas type properties for over 30 years. Our clients have included the General Services Administration (Federal agency), U.S. Navy, City and County of San Francisco, Shell Oil Company (now Aura Energy), Port of Oakland, former Mobile Oil Company, State of Maine, Port of San Francisco, Simmons Oil Company, and Arco.

The types of property appraised have included a gas refinery, tank farms, a proposed refinery site, oil and gas leases, and drill/pumping sites.

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Q3 ***Please General Describe Your Assignment?***

I was asked to identify and examine any influence that the proposed Sacramento Natural Gas Storage project may have on the market values and rates of appreciation of properties that lie within the boundaries of the former Florin Gas Field surface area.

Q4 ***Please Describe the Scope of Your Assignment.***

The Scope of the Assignment includes:

- Review all relevant project documents including all items set forth in the List of Documents Reviewed attached hereto as **Exhibit B.**

- Research neighborhood characteristics including, but not limited to, locational factors, economic conditions, demographic data, physical characteristics, planning restrictions and other factors.

- Inspect the subject neighborhood and the surrounding areas.

- Review neighborhood property records utilizing County assessor's records and various property databases to understand general property characteristics for the subject gas field area and the adjoining neighborhoods.

- Research and analyze data from the Sacramento MetroList MLS for recent sales and listings of residential properties in the subject area and the adjoining neighborhood.

- Engage DataQuick Information Systems to provide aggregate historical sales data for residential properties within the gas field area and for a similar defined residential area adjacent to the north.

- Review and analyze DataQuick and MLS historical sales price data for appreciation trends for residential properties within the gas field area and for the adjacent area to the north.

- Review and analyze a study by NorCal Market Perspectives of residential properties situated above and around gas fields in various parts of California and the U.S.

- Consider published research studies regarding various factors that may influence property values.

- Prepare written testimony of findings, provided below.

Q5 ***What Is Your Understanding Of The Proposed Sacramento Natural Gas Storage Project?***

Sacramento Natural Gas Storage proposes to operate a natural gas storage facility in the depleted Florin Gas Field, situated some 3,800 feet under the surface in southeast Sacramento. In addition to the gas field, the project will consist of a number of components, including a wellhead site, a compressor station, metering and gas

D2-275 (Cont.)

conditioning equipment, and approximately 2 miles of interconnecting buried pipelines. The storage capacity of the gas field is approximately 7.5 billion cubic feet.

Q6 ***Where Is The Project Located?***

The SNGS project is situated in the southeast portion of the City of Sacramento, and the southwest portion of Sacramento County. Approximately 75% of the Florin Gas Field is within the City of Sacramento, while the balance of the field lies in the County. The gas field is generally centered on Danny Nunn Park, at 53rd Avenue and Power Inn Road. The proposed well head site is to be situated on a 3.8 acre site at the northwest corner of Junipero Street and Power Inn Road, while the compressor site will be within the Depot Park industrial development, off of Fruitridge Road, on a 5 acre site. There will also be approximately two miles of buried interconnection pipelines.

Q7 ***Describe The Approximate Surface Boundaries Of The Florin Gas Field.***

The Florin Gas Field underlies approximately 287 acres of surface land, and extends generally from Elder Creek Road in the north to Florin Road on the south, and from 75th Avenue and Chris Avenue on the west to approximately ½ mile from Power Inn Road on the east. Approximately 75% of the field lies within the City of Sacramento, while the remaining 25% lies within Sacramento County jurisdiction. A map of the gas field surface area is included in my file.

Q8 ***When Was The Florin Gas Field Discovered?***

The Florin Gas Field was discovered in November 1977 by the Union Oil Company of California.

Q9 ***Over What Years Was The Gas Field In Production?***

The Florin Gas Field was in production from approximately July 1980 through July 1987.

Q10 ***Where Were The Former Gas Wells Located?***

There were a total of five producing wells. Two wells were situated in what is now Danny Nunn Park, at Power Inn Road and 53rd Avenue within the present subject residential neighborhood. The remaining three producing wells were approximately ¼ mile east of the residential area, near the end of Junipero Street, in the industrial zoned area to the east of Power Inn Road. Three additional wells were drilled but missed the field and were dry holes. These wells were also situated in the industrial area to the east of Power Inn Road.

The two wells within the park parcel were known as Proctor & Gamble #1 and #2. Well #1 was in production from May 1983 through November 1987, and Well #2 was in production from March 1984 through December 1985. The wells were filled and capped around 1990.

D2-275 (Cont.)

Q11 ***What Was Done With The Gas Wells After Production Ended?***

The wells were plugged, capped and abandoned in accordance with procedures outlined by the California Division of Oil, Gas and Geothermal Resources, the regulatory agency of the State.

Q12 ***What Are The Boundaries Of The Subject Neighborhood?***

The Florin Gas Field is situated in the Glen Elder neighborhood of southeast Sacramento, within the Fruitridge-Broadway planning area of the City of Sacramento. As indicated above, approximately 25% of the field lies within the County, being situated in an area known as the Fruitridge-Florin Study Area, which is within the City's sphere of influence and is bounded by the City limits to the north and west. The subject Glen Elder neighborhood is generally bounded by Power Inn Road to the east, Florin Road to the south, Lemon Hill Avenue to the north, and 75th Street to the west. The Avondale neighborhood, which has generally similar characteristics, adjoins Glen Elder on the north and extends to Fruitridge Road.

Q13 ***What Are The General Types Of Property Uses Within The Neighborhood?***

The subject neighborhood is generally comprised of single-family residential uses to the west of Power Inn Road and industrial uses to the east (Florin-Perkins Industrial area), with retail and services being situated primarily along Florin Road, Elder Creek Road and Fruitridge Road.

Q14 ***When Was The Glen Elder Area Annexed To The City Of Sacramento?***

The portion of the Glen Elder neighborhood generally north of 53rd Avenue to Elder Creek Road was annexed to the City in 1959, while Florin Reservoir Park (now Danny Nunn Park) was annexed in 1962. The area west of the Park, south of 53rd and extending to the present City limits, was annexed in 1970.

Q15 ***Please Describe The Neighborhood's Development History, Including Its Former Uses.***

Prior to the mid-1950's the subject neighborhood was primarily composed of rural farmlands. Development of the Glen Elder neighborhood generally began in the mid-1950's in the northern portion, adjacent to Elder Creek Road, extending southward to 53rd Avenue, the City boundary, over the period 1955 to 1961. There were also small pockets of development in the County, adjacent to and north of Florin Road, in the 1950's. The residential areas in the City to the west of Danny Nunn Park and south of 53rd Avenue were developed during the period from 1978-88.

Florin Reservoir- Danny Nunn Park, at the southwest corner of 53rd Avenue and Power Inn Road, was formerly known as Florin Reservoir Park. Although the name of the park has changed, the park is the site of a 10 million gallon underground water tank for the City of Sacramento water system.

Former Florin Gas Field Wells- The parcel on which the park is located was also the site of two natural gas wells for the Florin Gas Field (see parcel map 43-26 in my file). The

D2-275
(Cont.)

wells were identified as Proctor & Gamble #1 (API #06720293) and #2 (API #06720231). Proctor & Gamble #1 was drilled in 1982 to a depth of 4,060 feet, and was in production from May 1983 through November 1987. The well was filled and capped in 1990. Proctor & Gamble #2 was drilled in 1983 to a depth of 4,693 feet, and was in production from March 1984 through December 1985. The well was filled and capped in 1990. During this time, much of the residential neighborhood in the vicinity was developed.

Q16 ***What Are The General Zoning Designations In The Neighborhood?***

Within the City Limits:

R-1- Standard Single Family Zone- Primary zoning in the residential area to the west of Power Inn Road. Low density residential zone with densities of 7-8 units per acre.

R-1A- Single Family Alternative Zone- Pockets of R-1A limited to corner sites in areas near and south of 53rd Avenue. Low to medium density residential zone to a maximum of 15 units per acre.

C-2- General Commercial Zone- Limited to corner parcels at Elder Creek and Power Inn Roads. Allows a wide range of retail and service businesses.

M-2 (S)- Heavy Industrial Zone, with additional site improvements for an industrial-park like setting ("S" overlay). Allows manufacturing uses and other industrial processing to the east of Power Inn Road.

Within the County portion:

RD-5- Most common single-family residential zone where both public water and sewer are available. Comprises core of neighborhood lying within the County south of Tierra Glen Way.

RD-10- Most common duplex zone, with a maximum of 10 units per acre allowed. Pockets of RD-10 zoning extend along Florin Road and Power Inn Road.

LC- Limited Commercial Zone. Allows a wide range of retail goods and services on typically smaller individual lots in the subject neighborhood at the corner of Power Inn and Florin Roads.

M-2- Heavy Industrial Zone. Primarily larger interior sites off of Power Inn Road, north of Florin Road.

M-1 (F)- Light Industrial Zone. Allows fabrication, assembly, manufacturing and processing. The (F) overlay refers to flood-combining zone within the 100 year flood plain. These areas lie adjacent to Power Inn Road in the County.

D2-275 (Cont.)

Q17 ***Describe Any Identified Special Districts That Overlay The Subject Neighborhood Or A Portion Of The Neighborhood.***

Army Depot Redevelopment Area- This redevelopment area covers some 1,420 acres of land and was adopted in March 1995, after the Sacramento Army Depot (off Fruitridge Road) was scheduled for closure in 1994 under the Base Closure and Realignment Act of 1990. The Redevelopment area generally centers on the Depot and extends approximately one mile in all directions, having been amended in 2004 to include much of the Avondale and Glen Elder residential neighborhoods, extending south to the pre-1970's city limit. The goals of the redevelopment area include promotion of new private sector investment in the Depot facilities, correcting environmental deficiencies, development of employment opportunities, and preservation and development of affordable housing.

Florin-Perkins Enterprise Zone/Army Depot Enterprise Zone- This is a 2,500 acre industrial area generally bounded by Folsom Boulevard to the north, Florin Road to the south, Power Inn Road to the west and Watt Avenue to the east. The former Sacramento Army Depot (now Depot Business Park) lies near the center of this zone.

Q18 ***What Are The General Characteristics Of The Land In Terms Of Topography, Soils, Drainage, Flood Risk And Designated Seismic Zones?***

The subject neighborhood is generally level, sloping slightly from northeast to southwest, and has an elevation of approximately 30-35 feet above sea level. The subject is an urbanized area improved with roadways and buildings, and most areas are underlain by fill as a base. According to the Phase I Environmental Assessment for the proposed wellhead site at 6881 Power Inn Road (NEC of Junipero Street), soils in the area are primarily San Joaquin sandy loam series that have relatively high clay content and have a high shrink-swell potential which may adversely effect inadequately prepared foundations.

The subject neighborhood lies within the Morrison Stream Group drainage basin, a 105 square mile watershed with tributaries leading to the Sacramento River. Morrison Creek and its tributaries have been relocated and channelized over the years when land development took place, particularly with the construction of the Sacramento Army Depot in 1945.

In terms of flood risk, according to FEMA Community Panel 060266-0015F, dated July 6, 1998, most of the subject neighborhood is within Zone X, areas outside the 100-year floodplain. Areas along Morrison Creek, to the north of Elder Creek Road, are within Zone AE, within the 100-year floodplain with base elevations indicated, while the areas along the channel extending through the Glen Elder neighborhood, including the portion of open concrete channel just north of 53rd Avenue, are designated Zone A, within the 100-year flood plain.

According to the California Geological Survey, there are no mapped Alquist-Priolo Special Studies seismic zones in Sacramento County. The closest potentially active

D2-275 (Cont.)

mapped fault is the Dunnigan Hill fault, approximately 19 miles northwest of Sacramento.

Q19 ***Describe Any Major Easements Affecting The Subject Neighborhood.***

High Tension Lines- There is a 100-foot wide SMUD overhead power transmission line running in an east-west direction across the residential neighborhood just north of Vallecitos Way. The power lines are 230kV and 69kV. Additional power transmission lines run adjacent to the east side of Power Inn Road, in a north-south direction, opposite the subject residential neighborhood. A SMUD substation is situated on Power Inn Road, just south of 48th Avenue on an approximate one-acre site.

Drainage Channels- Inspection of the neighborhood, and reference to USGS historic and current topographic maps and FEMA flood maps, indicates that there is a drainage channel running through the subject neighborhood. The channel begins just south of 48th and Power Inn Road, running southward parallel to the road, turning in an east-west direction between 52nd and 53rd Avenues across the subject neighborhood, eventually joining another canal system leading to the Sacramento River to the west.

Q20 ***What Are The Characteristics Of The Glen Elder Neighborhood In Terms Of Access, Utilities, Parks, Schools, Shopping And Community Services?***

Access- Regional access to the subject area is via Highway 50 to the north, with an interchange at Power Inn Road, and via Highway 99 to the west. Major east-west corridors include Fruitridge, Elder Creek and Florin Roads, while north-south routes include 65th Street, Power Inn Road and Florin Perkins Road.

D2-275 (Cont.)

Utilities- Domestic water in the subject neighborhood is supplied by the City of Sacramento within the City limits, and by the Tokay Park Water Company and the Florin County Water District in the area outside the City. Sacramento Municipal Utilities District (SMUD) supplies electric service to the area, while natural gas is supplied by Pacific Gas and Electric (PG&E). There is a 10 million gallon water storage tank situated under Danny Nunn Park.

Parks- Danny Nunn Park (formerly Florin Reservoir Park), situated at 6920 Power Inn Road (SWC of 53rd Avenue), is the only neighborhood park located near the facility. The park encompasses 16 acres and is improved with two soccer fields, a rugby field, a basketball court, and picnic and playground areas.

Schools- There are three elementary schools in the Glen Elder neighborhood: Samuel Kennedy Elementary School at 7037 Briggs, Camella Elementary School at 6600 Cougar, and Elder Creek Elementary at 7934 Lemon Hill. There is a middle school situated just south of Florin Road, and West Campus High School is located on 58th Street north of Fruitridge Road.

Shopping- The primary shopping area in the subject area is along Florin Road to the south, and includes the Florin Mall to the west at Stockton Boulevard.

Community Services- Fire services in the area are provided by mutual aid between the Sacramento Fire Department (SFD) and the Sacramento Metropolitan Fire District (SMFD). SFD has a station at 5642 66th Street. Police services are provided by the Sacramento Police Department with a substation at 5303 Franklin Boulevard approximately 5 miles from the project area. The Sacramento County Sheriff's Department maintains a station near the Florin Mall on 65th Street. There is a community library just south of Florin Road.

Q21 ***In General, How Do Schools In The Subject Neighborhood Compare With Those Of Surrounding Neighborhoods In Terms Of State Rankings?***

According to Realtor.com, the average ranking for schools in the subject Glen Elder neighborhood is "4". The Fruitridge Manor neighborhood to the northeast also has a "4" average ranking, while the balance of the surrounding neighborhood within the Sacramento City limits have rankings of "5" through "7", and include the Southeast Area, Fruitridge, Tahoe Park, and Tahoe Park East and South.

Q22 ***What Are The Demographic Characteristics Of The Subject Neighborhood?***

The following is a brief summary of demographic highlights from the portion of the subject neighborhood to the south of Elder Creek Road. The report was generated using a ½ mile radius search centered on Danny Nunn Park at 53rd and Power Inn Road. The full report is included in my file.

Demographic Summary	
2008 Population	4,073
Population Change (1990-2000)	+0.53%/yr.
Population Change (2000-2008)	+0.06%/yr.
Median Age	29.4 yrs.
Median Age (Sac. County)	33.8 yrs.
Median HH Income	$41,228
Median HH Income (U.S.)	$53,154
Median HH Income (Sac. County)	$49,477
Total No. of Households	1,099
Avg. HH Size	3.7
Avg. HH Size (Sac. County)	2.6
Owner Occupied Homes	58.3%
Renter Occupied	35.7%
Vacant Units	6.0%
High School Graduates	27.6%
High School Graduates (Sac. County)	83.3%
Bachelors Degree	6.2%
Bachelors Degree (Sac. County)	24.8%

D2-275 (Cont.)

Q23 ***Within The Subject Portion Of The Glen Elder Residential Neighborhood, What Are The General Subareas?***

The subject portion of the Glen Elder neighborhood (within the Florin Gas Field) generally lies south of Elder Creek Road and extends south to Florin Road, and is bordered to the east by Power Inn Road and 75th Street/Chris Avenue to the west. The neighborhood is comprised of a northern portion of homes (generally north of 53rd Avenue) constructed from 1955 to 1961, areas to the south of 53rd Avenue constructed in 1978 through 1988, an area of homes in the County, near Florin Road, constructed in the 1950's, and pockets of relatively new construction off of Power Inn Road and 50th and 52nd Avenues, and along Othel Way.

Q24 ***What Land Uses Are Situated Within The Florin Gas Field Surface Area?***

Approximately 2/3 of the area has primarily single-family residential uses (717 parcels), approximately ¼ contains commercial or industrial uses (42 parcels), and the balance of the surface area is owned by the City (11 parcels).

Q25 ***What Development Activity Took Place In The Subject Residential Neighborhood During The Period The Gas Wells Were In Production?***

During the operating period of the gas wells situated in what was Florin Reservoir Park (1983-1987), substantial portions of the subject neighborhood were developed, including the area directly adjacent to and west of the park (1982-1988), and homes along the north side of 53rd Avenue, near Power Inn Road and opposite the park (1984). Other significant portions of the subject neighborhood adjacent to the Park were constructed during the period 1978 through 1981.

D2-275 (Cont.)

Q26 ***What Are The General Characteristics Of The Properties In These Areas In Terms Of Home Sizes, Age, Quality, Condition, And Lot Sizes?***

Northern portion between Elder Creek and 53rd Avenue- This area is primarily comprised of single-family homes of between 888 and 1,000 square feet, having two or three bedrooms and one bath, situated on lots of 9,500 to 11,300 square feet and constructed between 1955 and 1961. Homes in this area are generally of fair quality and in average to fair condition, and it is not uncommon for residences to have security bars on windows and front yards with chain link fencing.

South of 53rd Avenue to City Limits (Tierra Glen Way)- This area is primarily comprised of single-family homes of between 1,054 and 1,642 square feet having three or four bedrooms and two bathrooms, situated on lots of 6,500 to 8,000 square feet and constructed between 1978 and 1988. Homes in this area are generally of average quality and in average condition, most being adequately maintained. There are fewer vacant and listed properties in this southern portion of the Glen Elder neighborhood.

North of Florin Road to City Limits- This area is primarily comprised of single-family homes of between 850 and 1,780 square feet having two or three bedrooms and one or two bathrooms, situated on lots of 10,000 to 12,000 square feet and constructed between 1950 and 1978. The homes in the area closest to Florin Road are the oldest and tend to

be smaller, while the homes adjacent to the north were built later and are somewhat larger. Homes in this area are generally of average quality and in average condition, most being adequately maintained.

Pockets of New Construction- Within the subject neighborhood there are three pockets of new construction: along 52rd Avenue off of Power Inn Road (Glen Elder Estates); along Othel Way between 53rd Avenue and Power Inn Road; and, on Keasling Court, north of 50th Avenue, just west of Power Inn Road. The homes along 53rd Avenue and along Othel Way were constructed in 2006, and are primarily three to five bedroom, two bathroom homes on lots ranging from 5,200 to 9,000 square feet. The homes along 53rd Avenue range in size from approximately 1,725 to 2,110 square feet, while the homes on Othel Way range from 1,124 to 1,411 square feet. The 35 homes on Keasling Court, known as Glenwood Homes, were constructed under the direction of Mercy Housing, an affordable housing developer. Mercy Housing's Mutual Self-Help Housing program offers the opportunity for families to commit to working on their homes as a means of earning sweat equity for their down payment. The development was dedicated in April 2008.

Q27 ***What Is The Recent History Of The Residential Market Activity In The Subject Neighborhood (Within The Florin Gas Field Area)?***

That information is summarized on the following table:

Single Family Residential Sales- Glen Elder, south of Elder Creek Road

Year	No.	Median	Average	Avg. $/SF	% Chg.	Avg. SF
YTD 2008[1]	15	$112,000	$131,347	$113.62	-41.4%	1,156
2007	25	$255,000	$246,614	$193.90	-12.0%	1,272
2006	61	$330,000	$320,415	$220.44	-5.5%	1,454
2005	83	$282,000	$276,799	$233.15		1,187

Sales activity for 2008 has consisted primarily of REO's with 13 of 15 transactions being for bank-owned properties. The changes in value for the subject area are similar to those experienced by the Glen Elder and Avondale neighborhoods north of Elder Creek Road, which are outside of the Florin Gas Field area.

Q28 ***In General Terms, What Is The Highest And Best Use For The Various Areas In The Neighborhood?***

Within the subject residential areas west of Power Inn Road, the Highest and Best Use of the properties is for continued use as single family residential with eventual upgrading and expansion of homes in certain areas as economics permit. Many areas of the subject neighborhood are improved with small homes on what would now be considered good-sized lots of 10,000 to 12,000 square feet.

D2-275 (Cont.)

[1] Through July 5, 2008.

While the area to the east of Power Inn Road is zoned M-2 (S), Heavy Industrial, upgraded landscaping is required for new development to be more like a business park. A number of properties along Power Inn Road are improved with older metal buildings with fairly low coverage, and the expectation over time would be for continued industrial use, but with some re-development.

Q29 ***What Are The Historic And Recent Residential Sales Price Trends Within The Florin Gas Field Surface Area As Compared With The Adjacent Comparable Residential Areas?***

A summary comparing home sales data for the subject gas field area (Area I) and the adjacent area north of Elder Creek Road (Area II) for the period 1989-2008 is included in my file (See **Exhibit B**). The area defined as Area II is outlined on a map, and is comprised of the portion of the Glen Elder neighborhood north of Elder Creek Road and the eastern portion of the Avondale neighborhood north to Fruitvale Road. As shown in the following table, these areas (Areas I and II) are very comparable in terms of home size and age as can be seen in the comparison chart that includes data on average year built and average home size for the survey years.

Average Percent Value Change (1989-2005)				
Area	**Med. Price**	**Avg. Price**	**Med. $/SF**	**Avg. $/SF**
I- Gas Field	+9.25%	+9.3%	+9.0%	+9.2%
II- Adj. to North	+8.9%	+9.0%	+9.8%	+9.85%

Analysis of the home price data indicates that the median home price for homes in the subject gas field area increased from $68,500 to $282,000 for the period 1989-2005 (an average increase of +9.25% per year), while Area II home prices increased from $61,500 to $242,000 over the same period (an average increase of +8.9%). Average price showed a similar trend for the two areas with the Area I average price increasing an average of +9.3% per year and Area II increasing at +9.0%.

Home sales data since approximately August 2005 is problematic, as a good portion of the sales do not represent market value due to conditions of sale, being primarily short sales and REO's. Nonetheless, the change in the average dollar per square foot value for the subject gas field area from 2005 until July 5, 2008 (-48.5%) is similar to that experienced by the portion of the Glen Elder and Avondale neighborhoods to the north of Elder Creek Road that are outside of the Florin Gas Field area (-53.3%).

Q30 ***Will The Construction And Operation Of The Proposed SNGS Storage Project Have Any Cost Impact On Homeowner's Insurance For Properties Overlying The Gas Field?***

According to a study conducted by Shawna Ackerman, there is no cost impact. Her study results are included in my file (See **Exhibit B**).

D2-275 (Cont.)

Q31 ***What Is The Evidence Regarding Home Price Appreciation For Other Neighborhoods Situated Above Gas Storage Fields?***

A comparative study of values for single-family homes situated above gas storage fields was conducted by Market Perspectives, and included gas storage fields in Lodi, CA; Goleta, CA; Playa del Rey, CA; St. Louis, MO; and Houston, TX. The study compared values for homes inside and outside of the surface gas storage field area in each location. In each case, the study found no significant differences in rate of home value appreciation due to location inside or outside of the surface gas field area. The results of the study are included in my file (See **Exhibit B**).

Q32 ***Does The Data Gathered By Market Perspectives Conform To Your Own Knowledge Of The Impact Of A Deep Oil Or Gas Field On Surface Land Value?***

Yes, my experience in appraising property rights for over 45 years and analyzing the impact of deep tunnel easements and extraction rights has indicated that they have nominal impact on surface land uses, except in situations where there is a visual or noise interference, which is not the case with the SNGS project.

Q33 ***Mr. Gimmy, I Want To Ask Your Opinion About The Impact Of The Construction And Operation Of The SNGS Project On The Value Of Residential Property Overlying The Reservoir. Your Answer Should Be Based On The Following Assumptions And Any Other Information You Have Obtained Or Developed In The Course Of This Assignment. Please assume The Following:***

A. The SNGS project EIR has been certified by the lead agency, the California Public Utility Commission ("CPUC");

B. The SNGS project has been granted a Certificate of Public Convenience and Necessity by the CPUC finding that the SNGS project is in the public interest allowing the project to proceed.

C. The California Division of Oil Gas and Geothermal Resources has approved the use of the Florin Field and the proposed construction of wells for the SNGS Project;

D. The SNGS Project design meets or exceeds all applicable requirements set forth in the regulations of the U.S. Department of Transportation, Office of Pipeline Safety;

E. The City of Sacramento has issued a conditional use permit for construction and operation of the SNGS Project;

F. Storage rights have been obtained as to all properties overlying the reservoir;

G. The landowner leases for the subsurface area to be used by the project call for payment of the pro rata share of each parcel overlying the reservoir of 4% of annual gross revenues generated by the project and estimated at $17,600,000 per

D2-275 (Cont.)

year vs. a minimum of $1,000/acre but not less than $500/per parcel and the other provisions of the SNGS storage rights lease form;

H. SNGS has proposed to enhance its security patrol services to include Danny Nunn Park and George Simms Community Center and also to work with the members of the Power Inn Alliance to unify and coordinate the SNGS security patrol with other security patrol services now in place and thereby strengthen and enhance overall community security.

I. The Community Foundation has been established on the terms and conditions proposed by SNGS with annual funding in an amount equal to 0.25% of annual gross revenues generated by the Project;

J. The City has dedicated the storage lease rentals allocable to Danny Nunn Park to use for the exclusive benefit of the Park facilities and program; and

K. Construction and operation of the SNGS project is expected to provide the economic benefits to the community set forth by Dr. Robert Fountain in his report. (See **Exhibit B**).

In Addition To The Foregoing Assumptions, Please Take Into Account The Following:

- Your knowledge and experience as an appraiser in performing valuation studies of unique and complex properties;
- Your experience in the appraisal of oil and gas properties in other locations;
- The Analysis conducted by Market Prospectives dated August 8, 2008 entitled "*Single-Family Home Appreciation Analysis Involving Underground Natural Gas Storage Facilities In St. Louis County, MO; Houston, TX; Goleta, CA; Playa del Rey, CA; and Lodi, CA;*"
- The opinion testimony of Shawna Ackerman regarding the availability of homeowner's insurance; and
- The other information set forth in your earlier answers herein and the List of Information Reviewed attached hereto as **Exhibit B**.

Q36 ***Now Then, Based On The Foregoing Assumptions And Information, Please State Your Opinion As To The Impact, If Any, That Construction And Operation Of The Project Will Have On The Value Of Residences Overlying The Reservoir.***

The construction and operation of the SNGS project will have no measurable negative impact on the values of residences overlying the reservoir. All construction activities will occur outside of the subject residential neighborhood, and while there may be some increased traffic on Power Inn Road associated with the construction activities, this will be temporary and would not result in property value changes. The above ground operations are to be situated outside the residential neighborhood and will be screened from view, therefore eliminating any observable visual impacts. The dedicated

D2-275 (Cont.)

contributions to Danny Nunn Park facilities and programs from the City, and the commitment of extended patrol services by SNGS, will have a positive effect on reducing levels of vandalism and crime in the area, and thereby, contribute positively to residential values. Lastly, the value of these residences will be enhanced as set forth in my answer to Question 38. It should also be noted that for residential properties overlying deep fields, such as this, no seller disclosure is required.

Q37 ***Based On The Foregoing Assumptions and Information, Please State Your Opinion As To The Impact, If Any, That Construction And Operation Of The Project Will Have On The Value Of Residences In The Near Vicinity Of The Reservoir?***

With regard to the value of residences in the near vicinity of the reservoir, there would also be no measurable negative impact on value.

Q38 ***Is The Compensation Of $500 Upon Signing And $500 Per Year Fair For A Typical Single Family Home Property?***

Yes. The SNGS offer is actually in excess of the fair rental shown in the Bertholf appraisal included in my file. Also, using a 6.8% capitalization rate ("Cap Rate") the payment represents an added value in the initial year of the lease of $7,353 ($500 per year ÷ 6.8% = $7,353). This amount also represents 5.6% of the average property value set forth in the table under Question No. 27. The 6.8% Cap Rate is taken from the Sacramento area Cap Rate charts published at page 2 of the August 1, 2008 edition of the Sacramento Business Journal, a copy of which is included in my file (See **Exhibit B**).

Q39 ***Assuming The Same Cap Rate Of 6.8% And Further Assuming A Total Expected Percentage Rent Of $2, 450 Per Acre In The First Full Year Of Operation, What Is Your Opinion As To The Added Value Provided By The SNGS Storage Lease To A One-Acre Parcel?***

The added value to a one-acre parcel is $36,029 ($2,450 ÷ 6.8% = $36,029).

Q40 ***Assuming The Same Cap Rate Of 6.8% And Further Assuming A Total Expected Percentage Rent Of $704,000 In The First Full Year Of Operation For The Entire 287 Acres, What Is Your Opinion As To The Added Value Provided By The Lease To The Entire 287 Acres?***

The added value is $10,350,000 ($704,000 ÷ 6.8% = $10,352,941, called $10,350,000).

Q41 ***Does That Conclude Your Direct Testimony?***

Yes.

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EXHIBIT A

QUALIFICATIONS OF ARTHUR E. GIMMY, MAI

California Certified General Appraiser No. AG009703
Wyoming Certified General Appraiser No. 415

Background Information

Graduate of University of California, Los Angeles, with B.S. degree in Business Education (1955) and M.Ed. degree in Education (1956).

Instructor in Business Administration at San Jose State College (1956-58) and U.C.L.A. (1958-59).
Instructor for the AIREA in the period 1972-75. Speaker at numerous conferences. Author of over 50 books and articles.

Engaged in real estate and business education, research, valuation, and advisory role since 1960. Received Professional Recognition Award from the American Institute of Real Estate Appraisers in 1975 and 1978. Received the George L. Schmutz Memorial Award from the Appraisal Institute in 1996 "In recognition of his special contribution to the advancement of appraisal knowledge."

General Experience

Real estate and business valuation services include economic, marketability and feasibility reports, highest and best use studies, and appraisal of intangibles. Counseling to investors regarding real estate investment decisions. Expert witness testimony and litigation support services for of all types of property and enterprises throughout the United States, especially complex valuation issues.

Major Publications

Movie Theatres, Appraisal Institute, 1999
Health Care Enterprises, Appraisal Institute, 1996
Elderly Housing, Appraisal Institute, 1988 and 1998.
Golf Courses and Country Clubs, Appraisal Institute, 1992 and 2003.
Fitness, Racquet Sports and Spa Projects, American Institute of Real Estate Appraisers, 1979 and 1989.
"Assigning Values to Management Contracts", **Mergers and Acquisitions**, January/February 1986.
"The Doctor's Office - An Intimate Examination", **The Appraisal Journal**, October, 1975.
"Appraisal of Tennis Clubs", **Encyclopedia of Real Estate**, 1978.
The Ambulatory Surgery & Outpatient Services Manual (Chapter 15), 1997
"Resort Analysis in Mexico," **The Appraisal Journal**, October, 1976

Professional Associations

Life Member, Appraisal Institute (Cert. #3719)
Member, San Francisco Real Estate Board
Member, Institute of Business Appraisers
Member, American Planning Association
Member, International Racquet Sports Association
Member, National Golf Foundation
Institute of Real Estate Management

Specialties

Businesses/Goodwill
Ranches/Conservation Easements
Senior Housing
Healthcare Enterprises/Hospitals
Golf Courses & Private Clubs
Entertainment Venues/Theatres
Industrial/Special Purpose Plants
Airport Facilities
Billboards
Medical Offices/Clinics/Imaging /Surgery and Cardiac Centers
Hotels and Resorts
Estates/Partial Interests
Development Land
Contamination/Construction Defect Cases
Transmission Line Easements

Court Testimony

Qualified and testified as an expert on real estate and business use and value since 1962 before Federal Courts (in California, Guam, Kentucky and Nevada), Public Utilities Commission, Tax Courts, and Superior Courts in San Francisco, Marin, San Mateo, Alameda, Santa Clara, Orange, Sacramento, San Diego, Fresno, Los Angeles, Contra Costa, Stanislaus, San Joaquin, Butte, Merced, Santa Barbara, Riverside, San Bernardino, Sonoma, and Yolo Counties in California, Pima County in Arizona and others. Superior Court appointed referee in 1972.

Appraisal Institute Committees

Appraisal Journal Board (1999-2002)
Body of Knowledge (1999-2002)

EXHIBIT B

List of Documents Reviewed

1. Project Background & Information on Historic Production
    a. SNGS Regional & Project Maps
    b. CPUC Description of SNGS Project
    c. Documents Reviewed Regarding Florin Field Gas Production
    d. Report By John F. Matthews Regarding Field Well Abandonment
2. Maps of Sacramento Area Neighborhoods
3. Pertinent Excerpts From Sacramento's General Plan
4. Descriptions of Applicable Zoning Designations
5. Pertinent Zoning Maps
6. General Plan Information On The Fruitridge Florin Study Area
7. Information re Sacramento Army Depot Redevelopment Area
8. Maps of Flood Zone Areas, Creeks, And Water Systems
9. Information on Area Schools
10. Demographic Information
    a. STDB Radius Demographic Profile
    b. STDB Demographic, Income, and Market Profiles
11. Materials Consulted Regarding Hazardous Materials
12. Neighborhood Photographs
13. Information Consulted On Area Home Sale Trends
14. Market Perspectives' Gas Storage Field Residential Study
15. Article By Lisa Scherzer: *Three Factors That Reduce A Home's Value*
16. Realtor.com Map of REO's Auctioned Properties
17. Glen Elder Neighborhood Crime Maps and Statistics (Sacramento City GIG)

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18. Direct Testimony of Shawna Ackerman

19. Article re "Cap Rates" In August 1, 2008 Sacramento Business Journal, At Page 2

20. Report of Dr. Robert Fountain



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APPENDIX 15

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

DIRECT TESTIMONY OF

JAMES ROBERT FOUNTAIN, JR., Ph.D.

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail: ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: September 5, 2008

Q1 ***Please State Your Name And Business Address.***

Dr. James Robert Fountain, Jr. 1350 Hayes Street, Suite C-3, Benicia CA 94510

Q2 ***What Is Your Current Occupation?***

Economics Consultant.

Q3 ***Mr. Fountain, Do You Hold A Ph.D.?***

Yes.

Q4 ***Before Describing Your Ph.D. Work, Please State Where You Received Your Undergraduate Degree.***

BA in Economics, UCLA, 1969.

Q5 ***Did You Pursue Your Doctoral Studies At UCLA?***

Yes, including Masters, Doctorate, and Post Doctorate Research studies.

Q6 ***When Did You Receive Your Ph.D.?***

June 1977.

Q7 ***Please Describe Your Dissertation Work.***

My degree includes the major topics of housing, real estate, urban land economics, urban planning, finance, and research methodology. My dissertation is titled Residential Land-Use Density and the Housing Production Function, and is an analysis of how a variety of housing quality, space, land area, and other community and locational factors affect the demand for housing.

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Q8 ***Please Describe Your Work Experience Since Receiving Your Ph.D.***

a. Consultant for Housing and Community Development, Mayor's Office, City of Los Angeles.

b. Consultant, Urban Design Group, for the US Department of Housing and Urban Development.

c. Professor of Real Estate and Urban Development, College of Business, California State University, Sacramento (CSUS).

d. Research Director, Real Estate and Land Use Institute, CSUS

e. Research Director, Sacramento Regional Research Institute, Sacramento Area Commerce & Trade Organization.

f. Research Director, Applied Research Center, College of Continuing Education, CSUS

g. Consultant on Regional Economics and Forecasting, the Bank of Sacramento.

h. Research Consultant, California Public Employees' Retirement System.

i. Research Consultant, U. S. Properties Fund

j. Research Consultant, Institute for Health and Socio-Economic Planning.

Q9 ***Please List Any Articles You Have Authored Since Completing Your Dissertation.***

a. The Economic Impact of New Housing Construction in the Sacramento Region, for the Building Industry Association of Superior California, March 2004.

b. The Economic Benefits of Housing in California, for the California Building Industry Association, March 2004.

c. "Economic Outlook in 2003," in Comstock's Business, January 2003.

d. "Economic and Workforce Influence Factors for a Placer County University," for the Placer County Board of Supervisors. September 2002.

e. The Economic Impact of SACTO's Recruitment and Retention Program, published by the Sacramento Area Commerce and Trade Organization, November 11, 2001.

f. Report on the Sacramento Regional Economic Status. Business 2001 Conference, Sacramento Metropolitan Chamber of Commerce, March 2001.

g. Placer County's Role in the Region's Information Technology Development. Presentation to the Placer County Economic Development Summit, March 9, 2001.

h. The Economic Impact of SMUD Energy Conservation Programs. Prepared for the Sacramento Metropolitan Utility District, May 2000.

i. Economic Analysis of a Major Flood in the American River/South Stream Group Area of Sacramento. Prepared for the Sacramento Area Flood Control Agency, May 30, 2000.

j. "Economic and Housing Analysis: Current Events and Long Term Horizons," presented to the Building Industry Association of Superior California Annual Meeting, December 1997.

k. The Impact of the Housing Industry on the California Economy. For the State of California Department of Housing and Community Development. March 1996.

l. "The Long Term Future of the Sacramento Region's Economy," published in the Commercial Property Forum, fall 1994.

m. "Sacramento Region's Economy Declines for Third Year; Business, not Government, must Lead Recovery," article in the Sacramento Business Journal, Sept. 1993

n. "A Comparison of the Affiliated Cities, Sacramento, San Fernando Valley, and Tri-County Rental Housing Markets." August, 1988. Produced for the California Apartment Association.

o. California's Rental Housing: Past, Present, and Future." California Rental Housing, summer 1988.

p. "Monthly Business and Economic Report," Sacramento Business, Sacramento Metropolitan Chamber of Commerce, March 1985-October 1986.

q. "Costs and Benefits of Multiple Facilities for Industrial Firms", Journal of the American Industrial Real Estate Association, v. 11, October 1972.

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Q10 ***Please List Any Books You Have Authored.***

a. Co-author. Harvey Perloff, Tom Berg, Robert Fountain, David Vetter, and John Weld, Modernizing the Central City, Ballinger Publishing Company, Cambridge (MA), 1975.

b. Co-author. Lessons from the New Town Intown Experience, published by the School of Architecture and Urban Planning, University of California, Los Angeles, for the U. S. Department of Housing and Urban Development,

c. Co-author. Socio-Economic Study of Multiple Use Water Supply Reservoirs, Ralph Stone and Company, for the Bureau of Water Resources Research, US. Department of the Interior, Washington, DC. 1971.

d. Co-author. Restructuring of the Real Estate Brokerage Industry, by Frank G. Mittelbach and Fred E. Case, with consultants Robert G. Fletcher, Brenda Moscove, and J. Robert Fountain, Jr. Published by the Department of Real Estate, State of California,

Q11 ***Please Describe Any Academic Papers You Have Presented During Your Career.***

a. "Inclusionary Housing in Sacramento: An Informational Forum", sponsored by The Building Industry Association of Superior California and the Sacramento Board of Realtors, August 1980.

b. "An Analysis of Economic Development Data for the Sacramento SMSA", presented at the Second Annual Sacramento Regional Economic Outlook Forum, December 1978.

c. "Regional Data for Management Decision Making", presentation to the Management Systems Association, Sacramento, February 1978.

d. "An Empirical Estimation of the Housing Production Function", North American Meeting of the Regional Science Association, Philadelphia, November 1977.

e. "Tax Increment Financing for Central City Modernization," April 1976. A paper presented to the Los Angeles City Council and the Advisory Committee for the Downtown Renewal Project Area.

f. Development Potential for the Highway 50 Corridor in the Sacramento Region, for the Folsom Economic Development Corporation, December 2004.

g. California's Big Regions- What Makes Them Different and Where Are They Going? Presentation at the UCLA Forecast Seminar, September 8, 2004.

h. "Long-term Economic Structure and Work Force Requirements for the Sacramento Region," for the Sacramento Employment and Training Agency, Workforce Investment Board. June 2002.

i. "The economic role of Folsom in the Sacramento Region and Folsom's Extended Area of Economic Influence." Presentation to the Folsom Economic Development Corporation, October 29, 2001.

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j. "Economic and Housing Analysis: Current Events and Long Term Horizons," presented to the Building Industry Association of Superior California Annual Meeting, December 1997.

k. "Deciding our Region's Future: What we know, what we do not know, and the decision making infrastructure we need to make collaborative decisions," at the Valley Vision Beyond Polarization Forum, October 1997.

l. "Sacramento Regional Economic Forecast for 1996", Regional Economic Development Forum, sponsored by the Sacramento Area Commerce and Trade Organization; Sacramento Metropolitan Chamber of Commerce; and the Building Industry Association, March 27, 1996.

m. "Economic Status of the Sacramento Metropolitan Area and its Effect on Housing Sales". California Association of Realtors District III Annual Meeting, April 27, 1995.

n. "The Housing Market and Economic Trends in Sacramento," presented to the Sacramento Association of Realtors, March 1, 1994.

o. "Regional Economic Analysis and its incorporation into Appraisal Reports," a presentation to the Sacramento Sierra Chapter of the Appraisal Institute, April 9, 1992.

p. "Current Employment Trends in the Sacramento Region," for the Industrial Accounting Division, California Association of Certified Public Accountants, March, 1991.

q. Conference chairman and Presentation. "Sacramento in Recession?" Sponsored by the Sacramento Area Commerce and Trade Organization, the Sacramento Association of Realtors, the Sacramento Building Industry Association, and the Sacramento Tomorrow Coalition, April, 1990.

r. "The Effects of California's Recession on the Sacramento Economy," Real Property Section of the Sacramento County Bar Association, May 1991.

s. "Sacramento as a Boom Town: House Prices and Affordability in Sacramento's Present and Future," presented to the American Institute of Real Estate Appraisers, May 10, 1990.

Q12 ***Is A True And Correct Copy Of Your Curriculum Vitae Attached as Exhibit A Hereto?***

Yes.

Q13 ***Did SNGS Hire You To Perform An Economic Analysis Of The Proposed Natural Gas Storage Facility?***

Yes.

Q14 ***Please Describe Your Work For SNGS.***

I was hired to prepare an economic analysis of the value of the project to the City of Sacramento, and to the Sacramento region. The assignment included an analysis of the value of the project in terms of economic development of the region, possible effects to

D2-278 (Cont.)

key natural gas users including SMUD, and an econometric analysis of the total economic impacts including business activity, employment, income, and tax revenue generation.

The result of that assignment is a report titled "Economic Analysis of the Sacramento Natural Gas Storage Proposal", dated October 25, 2007. The report shows that the project will generate large economic impacts during both the one-time construction phase ($77,960,144 in the City of Sacramento, and $97,352,698 million throughout the region, including Sacramento) and a continuing revenue stream of revenues during the operating life of the project ($24,833,233 annually in the City of Sacramento and $25,746,336 annually region-wide, including the City).

The report also identifies major users of natural gas in the Sacramento region, including the SMUD electricity generation, State of California agencies, and others which can benefit from a lower-cost, local reserve supply of natural gas. A true and correct copy of the Report is attached as **Exhibit B.**

Q15 ***Please Describe The Methodology You Used To Calculate The Foregoing Project Benefits.***

The methodology used both economic development theory based on regional comparative advantage for evaluating the benefits of the reserve natural gas capability, and an econometric input-output model named IMPLAN to compute the full value of the project in terms of business, employment, income, and tax generation.

Q16 ***Is That Methodology One That Is Customarily Used By Economists To Analyze Economic Benefits Of Similar Projects?***

Yes, the USDA and the Forest Service developed IMPLAN in the mid-1970s with University of Minnesota economists for impact analysis of Federally-funded policies and projects. The Natural Resources Inventory and Analysis (NRIAI) and Social Sciences (SSI) Institutes support usage of IMPLAN throughout NRCS. The model is currently specified as the methodology required for analysis on many Federal and State public works and natural resources projects, and is widely used for testing the economic implications of a wide range of policy decisions.

Q17 ***Please Describe Any Analysis You Performed Regarding Whether The Local Neighborhood Will Receive Any Economic Benefits From SNGS Making Lease Payments For The Right To Store Natural Gas In The Florin Field?***

The lease payments to the City of Sacramento and to the residential property owners were analyzed. My conclusions are that the lease payments will increase the value of the property which generates the payments, and will make the properties more attractive and marketable in that they are generating a long-term net revenue stream with no offsetting costs to the property owners. This additional income will help property owners maintain their properties at a higher quality level, and decrease turnover and long term physical depreciation, all contributing to a higher level of community quality and real estate value.

Q18 ***Please Describe The Methodology You Used To Reach These Findings.***

The methodology for this analysis was an analysis of empirical research and publications which use economic and statistical models to assess the determinants of residential property values. The literature is significant on this topic, and shows that even small

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increases in household income and neighborhood quality can make substantial contributions to residential property values.

Q19 ***Is That Methodology One That Is Customarily Used By Economists To Analyze The Economic Effects Such Payments May Have On Local Communities?***

Yes. This methodology is appropriate for this type of non-physical determinants of residential property values in that the statistical method most widely used (multiple-regression analysis) can detect and evaluate a wide range of causal factors not identifiable with simple arithmetic or comparative methods often used in appraisals.

Q20 ***Did You Consider What Value, If Any, The Community Foundation SNGS Proposed To Establish Will Have On The Local Community?***

Yes, I am familiar with the proposed Community Foundation, which will be funded by a fixed percentage of project operating revenues each year. The agreement is for 0.25 percent of gross revenue up to $44,000 per year, with a minimum of $15,000 per year.

The value of this Community Foundation revenue depends on how it chooses to spend the funds. It would be appropriate for the Foundation to use the funds for community improvement activities which could include neighborhood beautification, landscaping, recreation facilities, social activities, community safety, maintenance of infrastructure and residential structures, or other activities which improve the attractiveness and cohesiveness of the community. As the Foundation is still in the formative stages, it is not possible to quantify any conclusions at this time, but the potential for the Foundation to contribute to community satisfaction and to residential property values is significant.

The methodology for this analysis is that described above regarding the value of lease payments, and is based on empirical and statistical studies of neighborhood satisfaction and residential property values.

The major difference between the effects of the Foundation payments and the lease payments is that the lease payments can be capitalized into the residential property values immediately, so a property owner who sells the property essentially takes the present value of the lease payments out of the community. By contrast, the Foundation payments and the value they create will remain located in the community for perpetuity

Q21 ***Does That Conclude Your Direct Testimony?***

Yes.

D2-278 (Cont.)

EXHIBIT A

VITA

James Robert Fountain, Jr.
395 West K Street
Benicia, CA 94510
(916) 719-2037

More Information and Access to Reports at
www.RegionalEconomics.Org

EDUCATION

Ph.D., Graduate School of Management, University of California, Los Angeles (UCLA), June 1977.
Major Field: Housing, Real Estate, and Urban Land Economics.
Minor Fields: Finance, Urban Planning, and Research Methodology.

Master of Science, Graduate School of Management, UCLA, 1971. Major: Urban Land Economics and Real Estate.

Bachelor of Arts, UCLA, 1969. Major: Economics.

EXPERIENCE

Present (since 1980). Consultant in real estate and land development. Clients include housing, industrial, and office development companies, mortgage lenders, real estate associations, and expert witness testimony.

D2-279

June 2005-present. Founder and Director, Applied Research Institute, California State University, Sacramento. This center provides applied research expertise over a wide range of topic areas and disciplines to clients in the business, government, and community leadership areas using access to CSUS Faculty in all Colleges and Schools.

June 2001-June 2005 Chief Economist, Sacramento Regional Research Institute, a joint venture of California State University, Sacramento and the Sacramento Area Commerce & Trade Organization.

June 2000 – June 2005. Special Consultant to the President on Regional Development, California State University, Sacramento.

1978-2001. Founder and Research Director, Real Estate and Land Use Institute, California State University, Sacramento. This research center provided research on topics related to regional economic development, housing, commercial development, and other land use variables for use in urban planning and real estate development decision making.

1976 - 1994. Professor of Regional Development and Urban Planning, School of Business Administration, California State University, Sacramento. (Currently Professor Emeritus.) Teaching areas at both the undergraduate and graduate levels included: real estate market and locational analysis, housing economics; regional economic development; mortgage markets; real estate finance; investment analysis; real estate appraisal; and urban planning.

1-1/2 years. Consultant and Community Development Project Coordinator, Mayor's Office of Urban Development, City of Los Angeles. Responsibilities included advising the Mayor and City Council on housing analysis, downtown redevelopment, and economic development policies.

Summary of Recent Research and Public Information Activities

Regional economic analysis including economic forecasts and projections, labor force and manpower studies, housing market studies, analysis of specific industry sectors, and economic impact analysis.

Local economic development analysis, including data and policy analysis performed for local government and community development agencies, and housing and redevelopment agencies.

Housing, Industrial, Commercial, Retail, and other land use and location studies for corporate decision makers.

Long range growth and development studies for lenders, industry associations, and government agencies.

Regional development analysis and publications for the Sacramento Area Commerce and Trade Organization; the Sacramento Metropolitan Chamber of Commerce; Placer County Department of Economic Development; and a number of city and county agencies.

Dr. Fountain's experience in economic analysis over a range of related topics such as economic forecasting, economic development, land use planning, housing market analysis, labor market and educational issues, and many others allows him to go "outside the box" and identify complex relationships between issues which have an integrated effect on the regional economic environment.

D2-279 (Cont.)

RESEARCH, PRESENTATIONS, AND PUBLICATIONS

An Econometric Model of Health Care in California, Institute for Health and Socio-Economic Policy, July 2008.

The Economic Impact Analysis of a California Water Board Brownfield Remediation Project: The Great Mall in Milpitas, prepared for the California State Water Resources Control Board, July, 2008.

The Economic and Fiscal Benefits of Natural Gas Production in Sutter County, prepared for VENOCO, INC. April 2008.

Economic Analysis of the Sacramento Natural Gas Storage Proposal, for California Natural Gas Storage, Inc., October 2007.

The Renaissance of the Strip Mall: Changing Residential and Retail Trends, a presentation at the Smith-Craine retail symposiums in San Francisco, Los Angeles, Orange County, and San Diego. 2006-2007.

Economic Impacts of CalPERS Investments, for the California Public Retirement System, April 2007.

Economic Impacts of Pension Benefit Payments on California and its Counties, for the California Public Retirement System, April 2007.

Retail Market Analysis and Supportable Retail Development Computations, April 2007, for the E. J. Plesko Company.

Economic and Fiscal Impacts of Proposed Condominium Construction in the City of Irvine, California, March 2007, for Starpoint Ventures and the City of Irvine City Council.

"Commercial Real Estate in a Time of Structural Change," a presentation to the Coldwell Banker International Annual Conference, Las Vegas, March 2007.

Community and Regional Economic Benefits of Housing Development, March 2007, for AKT Development.

"Economic Forum: an Executive Briefing," for the Bank of Sacramento, February 2007.

Economic and Market Analysis for the Proposed Diamond Creek Podium Condominium Project, February 2007, for Diamond Creek Partners, Ltd. and the City Council of the City of Roseville, CA.

D2-279 (Cont.)

Rating California Counties for Senior Apartment Development, December 2006, for the USA Properties Fund.

California and Sacramento Senior Housing Segmented Market Analysis, September 2006, for the USA Properties Fund.

Keeping California's Edge: the Growing Demand for Higher Educated Workers, April 2006, for the California Business Roundtable and the Campaign for College Opportunity

The Economic and Planning Costs of Open Space Requirements in Housing Development, for AKT Development Corporation, December 2005

Declaration and Deposition on the Fiscal and Community Aspects of Retail Development, Wal-Mart Stores, Inc. vs. the City of Turlock, CA, December 2005.

Development Potential for the Highway 50 Corridor in the Sacramento Region, for the Folsom Economic Development Corporation, December 2004.

The Sacramento Region Life Sciences and Medical Devices Industry Study, for a consortium of local governments in the Sacramento region, November 2004.

Litigation reports and filings on the South Tahoe Public Utility District vs. Heise Land & Live Stock Company, US District Court, October 2004, for The Diepenbrock Law Firm, Sacramento, CA.

California's Big Regions- What Makes Them Different and Where Are They Going? Presentation at the UCLA Forecast Seminar, September 8, 2004.

North Natomas Housing: Its Absorption Outlook and Economic Impacts for the City of Sacramento, for the Diepenbrock Law Firm, June 2004.

Economic Analysis of the Measure M Retail, Commercial, Industrial, and Housing Impacts in Sutter County, November 2004.

The Economic Impact of New Housing Construction in the Sacramento Region, for the Building Industry Association of Superior California, March 2004.

The Economic Benefits of Housing in California, for the California Building Industry Association, March 2004.

Analysis of the Impacts of Spectator Sports and Performing Arts Activities in the Sacramento Region, Sacramento Metropolitan Chamber of Commerce, March 2004

"The Sacramento Region Economy Watch", a monthly publication for the Sacramento Area Commerce & Trade Organization.

D2-279 (Cont.)

California Business Scorecard, for the SAER Group.

The Business and Professional Services Industries in Placer County, for the Placer County Department of Economic Development, March 2003.

"Economic Outlook in 2003," in Comstock's Business, January 2003.

"Economic Impact of Hewlett-Packard Employment Reductions in Roseville", February 2003.

Placer County University Curriculum Study, for the Placer County Board of Supervisors, January 2003.

"Long-term Economic Structure and Work Force Requirements for the Sacramento Region," for the Sacramento Employment and Training Agency, Workforce Investment Board. June 2002.

"Economic Impacts of the Housing Construction Industry in California," for the California Building Industry Association. November 2002.

"Economic Development Plan and Data Base for the City of Vacaville, Solano County." December 2002.

"The Biological Technology and Medical Devices Industry in Placer County," for the Placer County Office of Economic Development. May 2002.

"Economic Impact of the East End Office Project in Sacramento, California," for the State of California Department of General Services. June 2002.

"Economic and Workforce Influence Factors for a Placer County University," for the Placer County Board of Supervisors. September 2002.

Presentation: "Regional Economic Outlook for the Short and Long Term," to the Sacramento Bee newspaper Executive and Editorial Committees. March 6, 2002.

The Economic Importance of Parkshore Plaza Office Park in Folsom, California for Equity Office Properties Trust, March 16, 2002.

Presentation to the Placer County Annual Economic Development Summit regarding recovery prospects for regional economic development, March 15, 2002.

"The Sacramento Region as a Multi-Nodal Economy." Presentation to the Sacramento Area Council of Governments, November 15, 2001.

D2-279 (Cont.)

"The economic role of Folsom in the Sacramento Region and Folsom's Extended Area of Economic Influence." Presentation to the Folsom Economic Development Corporation, October 29, 2001.

"The Sacramento Region in Transition: The role of Restructuring and Conversion in Retention." Presentation to the Sacramento Metro Chamber Business Retention Forum, Oct 12, 2001.

The Economic Impact of SACTO's Recruitment and Retention Program, published by the Sacramento Area Commerce and Trade Organization, November 11, 2001.

Economic Analysis for a Community Hospital in Lincoln for Actium Development Corporation, Roseville, CA.

Economic Fundamentals of Housing Market Trends, for John Laing Homes, July 2001.

Editor, Regional Futures, May 2001, a compendium of research papers by Sacramento area academic researchers, for the Capital Region Institute and Valley Vision.

Executive Briefing: Long Term Economic Development Potential for the Sacramento Region. Golden 1 Credit Union executive staff. April 24, 2001

Labor Force Analysis for Placer County and the Sacramento Region. Prepared for Hewlett-Packard Corporate Offices, March 28, 2001

Placer County Information Technology Study, Placer County Office of Economic Development, March 2001.

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Placer County's Role in the Region's Information Technology Development. Presentation to the Placer County Economic Development Summit, March 9, 2001.

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The Information Technology Industry in the Sacramento Region, for the Sacramento Area Commerce and Trade Organization, May 15, 2000.

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Retail Market Analysis for the Proposed Natomas Center. A. J. Plesko & Associates, for the City of Sacramento, June 1999.

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"The Role of Placer County in the Region's Economic Future: South Placer Cities as a Growth Node," presented at the Placer County Economic Development Summit, March 26, 1999.

"The Demand for Age-Restricted Active Senior Citizens Housing in the Sacramento Region through the Year 2020 and Project Locational Requirements," presented to the Sacramento County Board of Supervisors, November 1998.

Westborough Neighborhood Market Analysis, for Lennar Communities, presented to the City of Sacramento planning department, October 1998.

Expert Panel Coordinator. "What do we know, and what do we not know, about the region's development and its future potential?" Presented at the Valley Vision Quarterly Board of Directors meeting, September 1998.

"Regional Economic Review," presented to the Board of Directors of the Sacramento Area Commerce and Trade Organization, September 23, 1998.

Consultant and Expert witness on housing market demand and absorption forecasting. Serrano Partners, 1998.

Regional Supplier Study, for the Sacramento Housing and Redevelopment Agency, June 1998.

"Woodland 2000: Woodland's Economic Future," for the Woodland Chamber of Commerce, May 1998.

Sacramento Region Biological Sciences Industry Study, for the Sacramento Area Commerce and Trade Organization, February 1998.

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Expert witness on housing market demand and regional economic analysis. First Interstate vs. Winncrest Homes, 1998.

"Economic and Housing Analysis: Current Events and Long Term Horizons," presented to the Building Industry Association of Superior California Annual Meeting, December 1997.

"Deciding our Region's Future: What we know, what we do not know, and the decision making infrastructure we need to make collaborative decisions," at the Valley Vision Beyond Polarization Forum, October 1997.

Project Director. Deer Creek Hills Market Analysis, for C. C. Myer Inc., July 1997.

"The Crisis in Home Ownership in the Sacramento Region," for the Sacramento Housing and Redevelopment Agency, May 1997.

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"Economic Impact Analysis of the Growth Control Initiative," for the Roseville (CA) Chamber of Commerce, November 1996.

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Project Director. Galt Economic Development Project, for the Galt Economic Development Committee, May 1997.

"Hotel - Conference Center Market Analysis," for California State University, Sacramento, February 1997.

"Sacramento Regional Economic Forecast for 1996", Regional Economic Development Forum, sponsored by the Sacramento Area Commerce and Trade Organization; Sacramento Metropolitan Chamber of Commerce; and the Building Industry Association, March 27, 1996.

Expert witness on regional economic development and demand for commercial property construction. Benvenuti vs. Pacific Central Properties, November 1996.

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"An Evaluation of Placer County as a Location for Electronics Industry Expansion." Placer County Economic Development Summit, March 1, 1996.

Expert witness on rural development potential. Russell v. MacDonald, et. al. July 1996.

Expert witness on suburban retail market development. Kearny Street vs. Orange Tree Partners, July 1996.

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Editor and co-author. "The Recession in Perspective". Building Industry Association of Superior California Newsletter, January 1996.

Expert witness. Winncrest vs. Pension Trust Fund, 1996. Deposition on regional economic trends and their effect on the housing market.

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Project Director. A Study of Hotel Demand and Supply in Downtown Sacramento, for Richard Benvenuti Enterprises, August 1995.

Economic and Fiscal Impact Analysis of the Cinnabar Development Project. For the McCuen Developments, presented to the El Dorado County Planning Commission and the El Dorado County Supervisors. August 1995.

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Project Director. Placer County Statistical Abstract, for the Placer County Office of Economic Development, 1995.

Editor. Greater Sacramento Economic Development Data Book, 1986 - present. Produced for the Sacramento Area Commerce and Trade Organization.

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Project director. Sacramento Regional Business Profile. Annual, 1984-present. Prepared for the Sacramento Area Commerce and Trade Organization.

Project Director. Major Manufacturers and Processors Guide, for the Sacramento Area Commerce and Trade Organization, annually 1988 - present.

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Project Director. Market Absorption Study for Light Industrial Development in the Sacramento MSA, for Balcor Corporation Highlands Reserve Project, 1995.

Editor and Project Manager. Economic Analysis of Energy Generation Alternatives, for the Sacramento Metropolitan Utility District, April 1995.

Consultant. Economic Development Tour of Five Capital Cities: Phoenix, Austin, Raleigh, Columbus, and Minneapolis, Sacramento Area Commerce and Trade Organization, April 1995.

"Economic Status of the Sacramento Metropolitan Area and its Effect on Housing Sales". California Association of Realtors District III Annual Meeting, April 27, 1995.

Project Director and Editor. Economic Analysis of the North Highlands Community and a Strategy for Mitigating the Effects of Military Base Closure. For the Sacramento Housing and Redevelopment Agency, 1995.

Project Director. Analysis of the Effect of Rent Control on Rental Housing Markets in Berkeley and Santa Monica, California. For the California Apartment Association, 1994.

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"The Long Term Future of the Sacramento Region's Economy," published in the Commercial Property Forum, Fall 1994.

"The Housing Market and Economic Trends in Sacramento," presented to the Sacramento Association of Realtors, March 1, 1994.

Project director. Analysis of the Land Requirements for Housing Development in Placer County, a study for the Stanford Ranch and the Building Industry Association of Superior California, November 1993.

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Consultant and project director. "Economic and Market Analysis for the City of Galt Downtown Revitalization Project," with the Urban Design Group, for the City of Galt, October - November 1993.

"The Role of Community and Business Leadership in Planning the Region's Economic Future," presented at the Regional Economic Development Workshop sponsored by the Building Industry Association of Superior California and the Labor and Business Alliance, Oct. 7, 1993.

"Office Development in Sacramento's Downtown Area, and its Relationship to Regional Economic Growth," a presentation to the Downtown First Committee, October 1993.

Consultant and Editor. An Evaluation of the Economic Impacts of SMUD's Conservation Programs, a study for the Sacramento Metropolitan Utility District, November 1993.

Presentation and Content Consultant. "Sacramento Regional Economic Structure and the Need for Economic Development Activity," at the Mayors Conference on Regional Economic Development, May 24, 1993

Project Consultant. Market Study for Downtown Condominium Development, a study for the Capital Area Development Authority. May 21, 1993.

"The Economic Development Process and Prospects for the Sacramento Region," Presented to the Board of Directors of the Sacramento Area Commerce and Trade Organization, May 12, 1993.

"Forecast of Housing Activity in the Sacramento Region during the Economic Recession," presented to the Custom Home builders Association of Sacramento, April 1993.

"The State of the Sacramento Regional Economy," presented to the City Council of the City of Sacramento, April 1993.

"The Regional Economic Development Process," a presentation at the Regional Economic Development Conference, sponsored by the Sacramento Area Commerce and Trade Organization, September 1992.

Consultant and editor. Planning Assumptions Study for the Sacramento County General Plan, for the Building Industry Association of Superior California, 1992.

Housing Market Absorption Study, for the CHAS Group, 1992.

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"Housing Markets in Sacramento Before, During, and after the Recession," a presentation to the Custom Home Builders Association, November 1992.

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"The Role of Economic Development in the Sacramento Economy," presented as part of the Economic Update and Real Estate Symposium, produced for the Sacramento Area Commerce and Trade Organization, May 28, 1992.

Editor and consultant. Economic Benefits of Food Processing Industries in the Sacramento Region, an economic impact analysis prepared for Sierra Quality Canners, May, 1992.

Analysis of the Development Potential of the Sunset West Project, for TerraQuest Inc., April 1992.

"Preliminary Market Analysis for the Peach Tree Mall", for First Union Real Estate Investments, April 1992.

"Regional Economic Analysis and its incorporation into Appraisal Reports," a presentation to the Sacramento Sierra Chapter of the Appraisal Institute, April 9, 1992. Part of a curriculum of continuing education credit for members of the Appraisal Institute.

Conference planner and content supervisor. Planning Housing Affordability and Availability for Sacramento's Future, produced for the AKT Foundation and the School of Business Administration, CSUS, March 20, 1992.

"The Role of Industrial Development in Sacramento's Economy," a presentation to the industrial Realtors division of Sylva-Kirk and Company, March 4, 1992.

Project consultant. Yuba City Economic Development Study, for the Yuba City Office of Economic Development, 1992.

"Current Economic Conditions and Prospects for the Sacramento Economy." a presentation at the Economic Update and Real Estate Symposium, sponsored by the School of Business Administration and the Sacramento Area Commerce and Trade Organization, February 1992.

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"The Current Conditions of the Sacramento Economy and Prospects for 1992," presented as part of the Economic Update and Real Estate Symposium, produced in cooperation with the Sacramento Area Commerce and Trade Organization and the Building Industry Association of Superior California, January, 1992.

Conference planner and Presentation. "Sacramento Annual Real Estate and Economic Outlook Forum." Annual meeting of the Sacramento Area Commerce and Trade Organization, September 11, 1991.

Project Director and editor. Credit Union Market Study and Locational Analysis. Schools Federal Credit Union, 1991.

Project Director. A Study of the Economic Multiplier Effects of the Blue Diamond Almond Growers and the Intel Corporation in the Sacramento Region. For the Sacramento Area Commerce and Trade Organization, August 1991.

Conference advisor and consultant. Wetlands regulations and the Land Development Process. For the AKT Foundation and the School of Business Administration, May, 1991

Conference planner and moderator. "New Neighborhoods for Sacramento's Future," a conference by the AKT Foundation and the School of Business Administration, February, 1990.

"Current Employment Trends in the Sacramento Region," for the Industrial Accounting Division, California Association of Certified Public Accountants, March, 1991.

Conference chairman and Presentation. "Sacramento in Recession?" Sponsored by the Sacramento Area Commerce and Trade Organization, the Sacramento Association of Realtors, the Sacramento Building Industry Association, and the Sacramento Tomorrow Coalition, April, 1990.

"The Effects of California's Recession on the Sacramento Economy," Real Property Section of the Sacramento County Bar Association, May 1991.

"Sacramento as a Boom Town: House Prices and Affordability in Sacramento's Present and Future," presented to the American Institute of Real Estate Appraisers, May 10, 1990.

"The State of the Sacramento Economy and its Impact on Commercial Brokerage," Camray Marketing Corporation, May 1991.
+
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"Demographic Trends and the Future of Rental Housing in California." Membership conference, California Apartment Association, October 1985.

Project director. Sacramento Source Book for Community Planners. Community Services Planning Council, 1985.

Consultant. Foreclosures in the California Residential Housing Market. For the Department of Real Estate, State of California, 1985.

Consultant. Design and collection of data for a state-wide economic development data base. California Department of Commerce. 1985.

Expert Witness. Cahill, et. al vs. Benvenuti, et. al. Superior Court, State of California, County of Sacramento, 1984.

Project director. Windbridge Retail Market Analysis, for Reiner and Bardis, presented to the City of Sacramento Planning Department, May 1984.

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Project director. Evaluation of Seven High Technology Industrial Locations in the Sacramento Region.. Study for AKT Development Company, submitted to the Sacramento County Planning Commission. June 1983

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D2-279 (Cont.)

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Project director. Industrial Location Analysis. Prepared for the Intel Corporation. 1982

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"Intermediate-Term Growth Prospects for the Sacramento Region", a presentation to the Management Conference, Pacific Telephone Company, March 1982.

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"Data Analysis for Regional Evaluation as a Part of the Appraisal Process", presentation to the Sacramento Chapter, Society of Real Estate Appraisers, March 1979.

"An Analysis of Economic Development Data for the Sacramento SMSA", presented at the Second Annual Sacramento Regional Economic Outlook Forum, December 1978.

"Regional Data for Management Decision Making", presentation to the Management Systems Association, Sacramento, February 1978.

"An Empirical Estimation of the Housing Production Function", North American Meeting of the Regional Science Association, Philadelphia, November 1977.

Residential Land-Use Density and the Housing Production Function. (Dissertation). Housing, Real Estate, and Urban Land Studies Center, Graduate School of Management, University of California at Los Angeles, May 1977.

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Consultant and co-author. Socio-Economic Study of Multiple Use Water Supply Reservoirs, Ralph Stone and Company, for the Bureau of Water Resources Research, US. Department of the Interior, Washington, DC. 1971.

Consultant and co-author. San Mateo County-Marsh Road Park and Reclamation Plan, Ralph Stone and Company, for the San Mateo (California) County Board of Supervisors, 1970.

D2-279 (Cont.)

EXHIBIT B

Economic Analysis of the
Sacramento Natural Gas Storage
Proposal

October 25, 2007

Prepared for

Sacramento Natural Gas Storage, LLC
2981 Gold Canal Drive
Rancho Cordova, CA

SACRAMENTO
Natural Gas Storage

Prepared by

Dr. Robert Fountain, Regional Economics Consultant
1350 Hayes Street, Suite 3-C
Benicia, CA

In Cooperation With

HDR | The Hoyt Company
660 J Street
Sacramento, CA

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(Cont.)

Executive Summary

The Sacramento Natural Gas Storage project will provide a Major Economic Asset for the City of Sacramento and the entire Sacramento Region.

The proposed Sacramento Natural Gas Storage will create large economic benefits not only from the construction and operational expenditures for the project itself, but also from the unique economic asset which a significant local supply of lower-cost, uninterruptable natural gas will provide for the region's major industries and public agencies. The largest single beneficiary may be the Sacramento Municipal Utility District, which generates most of the region's electricity using natural gas as the primary fuel, but many other industries, State Government, Universities, and others will benefit substantially.

What is the Sacramento Natural Gas Storage Project?

The Sacramento Natural Gas Storage (SNGS) Project is a natural gas storage operation which will utilize an ancient existing natural formation which is located 3,800 feet below the surface in the Florin area adjacent to the former Sacramento Army Depot. This formation contained naturally-occurring gas when discovered and exploited decades ago, but has not been utilized since then. A major asset of the formation is an area of impermeable layer of cap rock, which makes it a stable and safe storage area for natural gas.

The project will construct pipelines and gas pumping equipment to inject natural gas from existing sources into the storage area and retrieve it when needed. Users of the project will be large scale natural gas users who do not rely exclusively on the PG&E utility gas service, but who make purchases directly from suppliers.

Why We Need Natural Gas Storage.

1. The spot (short term delivery) price of natural gas from suppliers varies widely, and can be very high during periods of peak consumption. The ability to purchase and store natural gas locally during lower price times can greatly reduce the average price to users in the Sacramento Region, including the largest user, SMUD.

2. Natural gas purchased directly from suppliers reaches Sacramento users through a shared international pipeline. Natural gas use is increasing rapidly, and may soon exceed the delivery capacity of the pipelines serving the region during peak periods. We compete with all the other urban areas of the western US for the same pipeline capacity. The increase in use is not by residences, but by utility companies (SMUD uses natural gas to generate most of the region's electricity) and major industrial and government agencies. Stored natural gas could make a big difference if supplies from the pipelines fell below the Region's needs.

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3. Natural gas is by far the cleanest burning fuel available in mass quantities, and in addition to being the preferred fuel for electrical power generation, it also supports the development of renewable sources (like wind and solar) which are intermittent and need a clean alternative like natural gas during times of non-availability of the renewable energy source.

4. There is always a possibility of interruption of the pipeline supply, due to earthquakes, fires, floods, or even terrorist actions. In case of interruption, a large locally stored natural gas supply could make the difference between a significant economic disruption and a regional economy still in full operation.

5. Economic development in the region can be boosted by the availability of a large-scale natural gas storage facility. Few regions have the advantage of a natural, safe storage option, and the reduced average cost and immunity from disruption which that capacity will provide. Many major employers will see this as a significant economic advantage for the Sacramento Region.

Who are the Largest Natural Gas Users in the Sacramento Region?

In addition to SMUD, many major government and private organizations in Sacramento depend heavily on natural gas as a key energy source, and may use both the PG&E utility as well as private sources. The list includes examples of operations which use private natural gas sources, which could benefit from the proposed SNGS project.
The economic consequences to the region of interruptions or reduced growth in the economic sectors identified here would be enormous, and the growth and stability of these users are key to our economic well being. This is the most important value of the proposed SNGS project to our Region.

Major Natural Gas Users in the Sacramento Region

- Campbell's Soup Company
- Department of Motor Vehicles headquarters
- Folsom Prison
- Kaiser Hospitals
- Major canneries and food processors
- Mather Airport
- Mercy Hospitals
- Rice dryers at the Port of Sacramento
- Rock quarries (used for drying aggregates and asphalt production)
- Sacramento Municipal Utility District (for electricity generation)
- Sacramento Regional Transit (for CNG Bus Fleet)
- Sacramento State University
- State of California Department of General Services, for the Central Heating and Cooling Plant (serves 22 State buildings)
- Sutter Hospitals
- UC Davis Medical Center

Arranged alphabetically, Source: Interstate Gas Services

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What are the immediate economic benefits to the City of Sacramento and the Sacramento Region?

The SNGS project provides large measureable economic benefits to both the City of Sacramento and the entire Sacramento Region.

Benefits for the City of Sacramento.

The one-time construction phase will generate nearly $78 million in total business revenues within the City of Sacramento, create 213 jobs, and create $1.1 million in general fund revenues.

Economic Benefits from the Construction and Operation of the SNGS Facility

	Total Business Revenues	Employment	Employee Compensation	State and Local tax revenue generation	General Fund Revenue Generation
Benefits to the City of Sacramento					
One-Time Economic Benefits from Project Construction Phase	$77.96 million	213 positions	$12.034 million	$3.6 million	$1.1 million
On-going Annual Economic Benefits from Project Operation	$24.8 million annually	89 positions	$5.8 million annually	$1.59 million annually	$488,800 annually
Benefits to the Sacramento Region (including City of Sacramento)					
One-Time Economic Benefits from Project Construction Phase	$97.4 million	393 positions	$21.4 million	$7.04 million	$2.18 million
On-going Annual Economic Benefits from Project Operation	$25.5 million annually	98 positions	$5.99 million annually	$1.6 million annually	$507,200 annually

The Region includes the four counties Sacramento, Placer, Yolo, and Eldorado and all cities within them.

The on-going benefits to the City of Sacramento will be about $25 million annually in business revenues, 89 permanent positions, and nearly $489,000 annually in general fund revenues. The total of these annual benefits over the economic life of the project (expected to be over 50 years) will be a very large contribution to the City's economy and tax revenues.

Benefits for the Sacramento Region

For the entire Sacramento Region (including the City of Sacramento) the benefits are higher because the region captures some of the activities which are not located within the City of Sacramento.

During the one-time construction phase, the Region will receive $97.4 million in business revenues, supporting 393 positions, and generating $2.18 million in general fund revenues for all the cities and counties in the region.

For the on-going operations phase, the Region will receive $25.5 million annually in business revenues, supporting 98 permanent positions, and generate $507,200 annually in general fund revenues.

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Introduction

The proposed Sacramento Natural Gas Storage (SNGS) facility is a proposal to use an existing natural underground reservoir area to store natural gas for large users in the Sacramento region who do not depend entirely on the Pacific Gas & Electric natural gas utility. This topic is important because of the increasing importance of natural gas to electrical power generators and large industrial users, due to its role in reducing pollution and greenhouse effects, and as a backup source for interruptible renewable generation methods such as solar and wind. This report will identify the economic benefits to the City of Sacramento and the Sacramento Region which will occur as the result of this project.

Types of Economic Benefits

There are two types of economic benefits from this project. First, the direct impacts of the actual construction and operation of the project will generate expenditures which have large effects on regional business and government revenues, firms which provide materials and services to the project, to household consumption sectors, and to local government tax revenues. Some of these economic benefits are one-time only during the construction phase, but operational benefits will continue to flow for the full economic life of the project, expected to last over 50 years. These direct construction and operational benefits can be rigorously quantified and analyzed using economic impact models, which will provide a clear financial and employment view of the project's benefits.

The second type of economic benefits is created by the project's benefits to natural gas users. The storage facility does not generate any net new supplies of natural gas, but provides a way to increase supply in peak demand periods, allows users to hedge against the sharp volatility of natural gas prices during times of peak use, and provides a local reserve for use in possible times of shortages, supply interruptions, or other threats to supply continuity. This second type of benefits cannot be as rigorously quantified as the construction and operational benefits, but will in the long run be much more important to the economic growth and stability of the economy.

Geography of Economic Impacts

The SNGS facility will be located and operated within the City of Sacramento, and will create direct, measureable economic benefits which primarily accrue within the City. It would be erroneous, however, to underestimate the additional benefits which accrue to the rest of the region. The economic, employment, and fiscal benefits will be scattered throughout the region. This is especially true during the construction phase, where nearly half of the specialized construction labor, engineering firms, and other inputs to this type of highly specialized construction are based outside the City of Sacramento.

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In the long run, benefits will accrue to the entire Sacramento region. The major users of the SNGS storage will be large scale utility, government, and industry users of natural gas, who will benefit from lower average costs and a greater opportunity to hedge cost variations, assure a constant supply, and reduce risks of natural or other interruptions in supply. That will show up in the regional ability to attract and retain choice industries and firms, enhancing the region's economic growth and stability. This will benefit the City of Sacramento as well as the rest of the Regional economy, but the location of these future benefits within the Region cannot be predicted at present.

Description of the SNGS Project

The SNGS project is a natural gas storage operation which will utilize an ancient existing natural formation which is located far below the surface in the Florin area adjacent to the former Sacramento Army Depot. This formation contained naturally-occurring gas when discovered and exploited decades ago, but has not been utilized since then.

A geological representation of the field shows that the gas storage area occurs 3,800 feet below the surface, in an area of permeable sandstone which is ideal for storing gas. Equally important, the field is below a thick, impermeable layer of cap rock, which serves as the containment barrier for the stored gas. Multiple layers of shale, sand, water, and surface soil and clay occur above the cap rock.

This type of natural storage area is rare; many of the natural gas underground storage areas use salt formations or other geological structures which are not nearly as stable and impermeable as the cap rock structure of the Florin field.



Gas will be stored in an ancient geologic formation 3/4 of a mile underground (the old Florin Gas Field). A layer of permeable sand held natural gas there for millions of years until the gas was extracted in the 1960s.

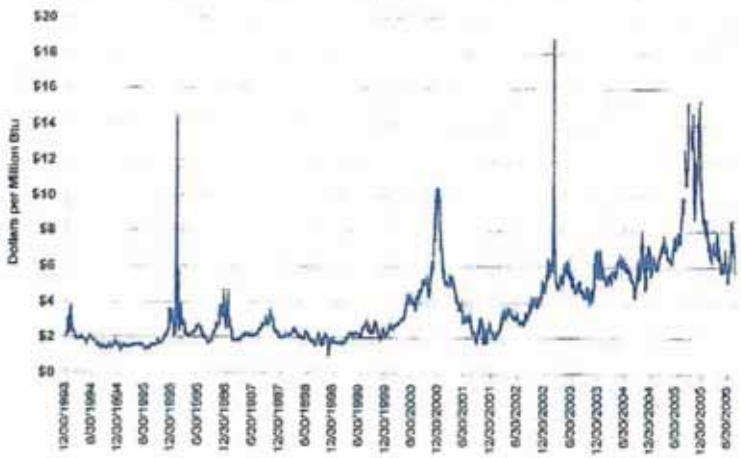
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The project will consist of constructing and operating the system required to bring in the natural gas from existing pipelines, compressing and pumping the gas into the well, and then retrieving the stored gas on demand. In addition to the mechanical systems for handling and delivering gas, security and safety systems are an extensive part of the system, as well as payment of storage rights fees to owners of land above the storage area, rental payments for space in the Depot Park for the compressor facilities, and establishment of a Community Foundation to support projects and activities for the residents of the surrounding community. The total cost of the construction of the project is estimated at approximately $58 million, while the annual operating revenues are estimated at $17 million during the initial year of operation.

The Benefits to Natural Gas Users

There are three major functional issues which the SNGS project addresses.

The first issue is the extreme volatility of spot (same day delivery) natural gas prices, especially in high demand periods such as very hot or very cold days. This is a cost of energy issue, where storing quantities of gas acquired during lower cost times can avoid the very high market prices during peak times.



The graphic shows that during recent years, short term (spot market) price spikes of 50% to 100% often occur, and some even higher peaks. The storage option allows users to purchase and store large quantities of gas during seasonally low price periods, and then retrieve and use the stored gas instead of making spot purchases.

The second issue is the increasing possibility for temporary curtailments as the nationwide and local storage facilities and delivery pipelines approach capacity utilization. This is a system capacity issue, but one which is increasingly important as environmental goals encourage the shift from dirty to clean fuels.

Sacramento's natural gas is supplied through an international pipeline system, shown in the adjacent figure. The PG&E pipeline (circled as the number 8 in the map) serves the Sacramento region. The gas sources are very distant, and other major metropolitan areas depend on the same gas pipeline.

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The problem is that the demand for natural gas, especially for large industrial users and for electrical power generation, is rising rapidly. While utility-provided natural gas usage is forecast to grow only slowly (0.9% annually) through the year 2025, the trend in natural gas use by private, non-core, non-utility users is projected to grow at a much higher 1.7% per year. The faster growth in non-core use is largely due to the shift by industrial and electrical generation users toward the cleaner natural gas source, and away from the regulated utility providers such as PG&E, to non-regulated providers, in order to have more control over the delivery and pricing of the resource. (Source: California Gas Report, Prepared by the California Gas and Electric Utilities, 2007.) This is exactly the users which the SNGS project is designed to serve.

Western US Natural Gas Pipelines

Source: California Gas Report, Prepared by the California Gas and Electric Utilities, 2007



1. Baja Norte/North Baja Pipeline
2. El Paso Natural Gas
3. Gas Transmission-Northwest (GT-NW)
4. Kern River
5. Mojave Pipeline
6. Northwest Pipeline
7. Palute Pipeline
8. PG&E Company
9. Questar Southern Trail
10. SDG&E Company
11. SoCalGas Company
12. TransCanada Pipeline
13. Transwestern Pipeline
14. Tuscarora Gas Transmission

The third issue is the risk-averse view of the vulnerability of the natural gas supply system to disaster interruptions of pipelines such as earthquakes, floods, fires, or terrorist acts which disrupt the pipelines and isolate regions such as Sacramento from the distant natural gas suppliers. While there have been no such interruptions, many large gas users have reviewed their costs of any such interruption, and are seeking risk reduction alternatives. Local storage of many-day supplies at a facility such as the SNGS project is a very sure, low cost risk solution for these users.

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The Region's Major Natural Gas Users

The SNGS project is designed to serve large users of natural gas, those who do not depend solely on PG&E core regulated distribution. The following discussion will identify many of those users, who will be major beneficiaries of the SNGS storage option.

The largest user of private source natural gas in the region is the Sacramento Metropolitan Utility District (SMUD), which uses natural gas to fuel most (60%) of its electrical generation. This is a statewide phenomenon, as natural gas is the cleanest option among the fossil fuels. Compared to the statewide average, SMUD also generates a larger than average percentage using large scale Hydro-electric sources, but a smaller percent is based on nuclear sources.

Even for the renewable sources used by SMUD, shown at right, the solar, wind, and small hydroelectric sources are categorized as intermittent sources, and require natural gas backup generation when the renewable source is not available. (Source: SMUD, A Summary Report by the Advanced Renewables and Distributed Generation Program)

In addition to SMUD, many major government and private organizations in Sacramento depend heavily on natural gas as a key energy source, and may use both PG&E core service as well as private sources or providers. The list includes examples of operations which use private natural gas sources, which would benefit most from the proposed SNGS project.

The economic consequences to the region of interruptions or reduced growth in the economic sectors identified here would be enormous, and the growth and stability of these users are key to our economic well being. This is the most important value of the proposed SNGS project to our Region.

Sources of Energy for Electrical Power Generation

	CA %	SMUD %
Natural Gas	50%	60%
Nuclear	16%	>1%
Hydro	15%	21%
Renewables	15%	15%
Oil	2%	0%
Coal	2%	4%

Sources:
SMUD Product Content Label 2007, www.smud.org/green
Platt's Powerdat, quoted in California's Greenhouse Gas Policies, Center for the Study of Energy Markets, UC Davis.

SMUD Renewable Sources

Source	Percent of Total Generation
Biomass and Waste	6%
Geothermal	4%
Small Hydroelectric	2%
Solar	<1%
Wind	2%

Major Natural Gas Users in the Sacramento Region

- Campbell's Soup Company
- Department of Motor Vehicles headquarters
- Folsom Prison
- Kaiser Hospitals
- Major canneries and food processors
- Mather Airport
- Mercy Hospitals
- Rice dryers at the Port of Sacramento
- Rock quarries (used for drying aggregates and asphalt production)
- Sacramento Municipal Utility District (for electricity generation)
- Sacramento Regional Transit (for CNG Bus Fleet)
- Sacramento State University
- State of California Department of General Services, for the Central Heating and Cooling Plant (serves 22 State buildings)
- Sutter Hospitals
- UC Davis Medical Center

Arranged alphabetically, Source: Interstate Gas Services

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Economic Impacts of the SNGS Project for the Economies of the City of Sacramento and the Sacramento Region

The analysis in the following section identifies the numerically quantifiable economic benefits from two phases of the project:

1. The construction and deployment phase of the project, which is a large one-time economic benefit to the City and the Region. This phase consists of construction of pipelines, pumping and processing equipment, administrative and operations facilities, security and monitoring systems, permits and other agreements with the City of Sacramento, negotiation of storage leases with nearby land owners and natural gas users, and other development costs.

2. The long-term operations of the facility, in which benefits flow from the energy cost savings to natural gas users to the SNGS facility, to regional business and industry natural gas users, to Depot Park as lease income for the compressor space, and to the land owners receiving storage rights fees.

While the construction phase benefits are large and be highly visible, the operational benefits are the real payoff to the City and the Region. A 50-year economic life is widely used for natural gas storage facilities, although such facilities actually have an unlimited economic life.

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Although the facility will be located within the City of Sacramento, direct measurable benefits also occur elsewhere in the region. For that reason, data on the Regional impacts as well as the City of Sacramento impacts are provided.

Methodology

The expenditures by SMGS during the construction and operational phases are not the complete picture of its economic impact. During the construction phase, the $58 million in direct expenditures goes partly to other firms which supply them with materials, equipment, machinery, expert services, electricity, transportation, even local government services. Then the employees of the construction firms and their suppliers spend their wages in the household consumption sectors, including retail, medical services, housing, education, and many others. The complete view of the construction impacts requires an econometric model which can predict how much of the construction funding will go to these other economic activities.

For that purpose, this study uses IMPLAN, an input-output model developed in the mid 1970s by the USDA, the Forest Service, and University of Minnesota economists for community impact analysis of Federally-funded projects. IMPLAN is currently specified as the required methodology on many Federal and State public works and natural resources projects and is widely used in California for CEQA reviews.

The IMPLAN model must be calibrated for each local economy where impacts will be measured. The calibration requires a model for the local economy which shows all of the productive sectors, and measures

the interconnections between them. The calibration is based on data from the US Bureau of Labor Statistics the ES-202 survey of local businesses, updated every two years. The data used in this is from the 2006 update, the latest available. Models are calibrated for the City of Sacramento and for the Sacramento Region (Sacramento, Placer, El Dorado, and Yolo Counties).

Construction Phase Economic Impact Generation

The generation of economic benefits for the City of Sacramento and the Sacramento Region are shown in the adjacent table. This table shows the construction phase economic impacts, and is based on the direct expenditures for construction activities.

SNGS Generation of Economic Impacts Construction Phase

Construction Phase: One-time Benefits	Direct Benefits $	Indirect Benefits $	Induced Benefits $	Total Benefits $
City of Sacramento	58,000,000	11,983,769	8,376,376	77,960,144
Sacramento Region (Includes City)	64,000,000	15,793,430	17,959,269	97,352,698

Notes:
All data in 2006 dollars
Sacramento Region includes Sacramento, Placer, Ed Dorado, and Yolo Counties
Data shown are for Total Revenues or Total Output

For the City of Sacramento, the direct construction expenditures are $58 million, but an additional $11.98 million in business revenues is generated through suppliers of goods and services (called indirect benefits) and an additional $8.37 million is generated in the household serving sectors (called induced benefits), for an overall total of $77.96 million over the construction period. This analysis illustrates the "economic multiplier" concept, in which $58 million generates a total of $77.9 million, or a multiplier of 1.34. This multiplier is relatively low because many of the highly technical skills and firms needed for this job are not located in the City of Sacramento, so some of the expenditures leak out of the City and the Region.

The Region captures a higher percentage of the revenues from the construction phase because it has more of the skills, materials, and services needed for the project. All of the numbers are somewhat greater for the Region than for the City of Sacramento. The Region receives a total of $97.35 million in total economic benefits, for a multiplier of 1.52 during the construction phase.

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Operations Phase Economic Impact Generation

The economic impacts appear to be much lower for the operating phase than for the construction phase, but this is deceiving. The operating phase impacts are an annual flow for the entire life of the project, with an expected economic life of over 50 years.

For the City of Sacramento, the direct impacts from operations in the first year is estimated at $17 million (total revenue). The indirect benefits of purchases from other firms adds another $3.85 million, and consumer benefits add $3.97, for a total economic impact of $24.8 million per year. The operating multiplier for the City of Sacramento is about 1.46, higher than its construction multiplier.

SNGS Generation of Economic Impacts Operating Phase

Operation Phase: On-going Benefits	Direct Benefits $	Indirect Benefits $	Induced Benefits $	Total Benefits $
City of Sacramento	17,000,000	3,858,944	3,974,289	24,833,233
Sacramento Region (Includes City)	17,000,000	3,858,944	4,887,392	25,746,336

Notes:
All data in 2006 dollars.
Sacramento Region includes Sacramento, Placer, Ed Dorado, and Yolo Counties
Data shown are for Total Revenues or Total Output

For the Region, the direct and indirect benefits are the same, but the induced consumer benefits are about $1 million higher, indicating the wider dispersal of employees and resulting consumer expenditures. The operating multipiler for the Region is about 1.51, slightly higher than the City.

Distribution of Economic Benefits, Construction Phase

The previous discussion was focused on the way the economy generates the economic multiplier; this section will show a different view, the composition or distribution of the economic benefits.

The distribution of the economic benefits is illustrated by using several different measures of incidence.

SNGS Composition of Economic Impacts Construction Phase

Construction Phase: One-time Benefits	Total Revenues $	Value Added $	Employee Compensation $	Employment (number)	State and Local Tax Revenues $	General Fund Revenue $
City of Sacramento	77,960,144	24,993,313	12,034,899	212.6	3,557,139	1,063,848
Sacramento Region (Includes City)	97,352,698	45,382,304	21,405,107	392.5	7,037,706	2,163,551

Notes:
All data in 2006 dollars.
The estimates for State & Local Tax Revenues are model estimates, and are not based on specific tax studies of each local government.
General Fund Revenues are computed from business and personal property taxes, local share of sales taxes, and other fees.
Data shown is the total benefits including direct, indirect, and induced benefits.

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The Total Revenues (also called Total Output) is the total received by all business firms, individuals, government entities, and any other entity receiving revenues from the project. Note that this includes all of the direct, indirect (suppliers), and induced (consumers) components of the total. The total revenue of $77.96 million for the City of Sacramento is the same number shown in the earlier table on construction benefits for the City. The Region, which captures more of the activity resulting from the SNGS project, will have $97.35 million in total revenues.

The Value Added is a subtotal of the total revenues which is a component of the Gross City Product (Like GNP). It subtracts from the revenues of each firm the expenditures it makes to other firms, leaving only the actual increase in value the firm adds to the materials and services it purchased. The concept of value added gives a view of the net productivity of the firm, and results from its use of capital, labor, management skills, and other real and intangible assets in its production process. The Value Added in the City of Sacramento from the SNGS project construction phase is about $24.99 million, while the Region will receive about $45.38 million.

The Employee Compensation is the part of Value Added which accrues to the employees of the business and government entities which receive revenues from the project. Employee compensation is not just wages and salaries, but includes the cost of all benefits such as medical coverage, vacation and sick leave, retirement benefits, employer social security contributions, etc. The employee compensation for the City of Sacramento will be about $12 million for the construction phase, while the Region will receive about $21.4 million.

The Employment measure is the only one which is not a dollar value. It represents the full-time annual equivalent employment generated by the project. Note that this is not necessarily a head count, as some employees are not utilized for an entire year, but several part time or temporary employees may be employed (as is typical in construction projects). The construction phase will employ over 212 employee years in the City of Sacramento and 392 in the Region.

The tax generation data in the table are from the IMPLAN model estimates, and are based on 2006 regional data. These are model estimates, and are not based on an actual study of the current tax structure in the City of Sacramento or the other Cities and Counties of the region.

The State & Local tax estimate shows all locally generated tax revenues, but cannot estimate the actual disbursements received by the local government in the rapidly changing tax structure in California.

General Fund Revenues are based on the business and personal property taxes, the local share of sales taxes, and other taxes and fees.

The model estimates show that for the construction phase of the project, the City of Sacramento would generate about $3.55 million in State and Local taxes, of which about $1.06 million will accrue to the City's general fund. For the Region, the total generation of State and Local Taxes would be about $7.03 million, with $2.18 million going to the general funds of all of the local governments in the region.

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Distribution of Economic Benefits, Operations Phase

Annual SNGS Composition of Economic Impacts, Opertions Phase						
Operation Benefits: On-going Benefits	Total Revenues $	Value Added $	Employee Compensation $	Employment (number)	State and Local Tax Revenues $	General Fund Revenue $
City of Sacramento	24,833,233	10,938,478	5,803,686	89.2	1,593,547	488,780
Sacramento Region (Includes City)	25,547,178	11,316,964	5,992,591	98.2	1,648,936	507,205

Notes:
All data in 2006 dollars.
Sacramento Region includes Sacramento, Placer, Ed Dorado, and Yolo Counties
The estimates for State & Local Tax Revenues are model estimates, and are not based on specific tax studies of each local government.
General Fund Revenues are computed from business and personal property taxes, local share of sales taxes, and other fees.
Data shown is the total benefits including direct, indurect, and induced benefits

A similar examination of the operating phase economic benefits is shown in the table. It is important to remember that these are annual values, over a 50-year economic life of the project. Multiplying the annual values over even 10 years makes them very large compared to the data for the construction phase, discussed earlier.

It is noteworthy that the values for all these measures are similar for the City of Sacramento and the Sacramento Region, showing that the operating benefits accrue more to the City than do the construction phase benefits.

- The annual Total Revenues in the City will be about $24.8 million and a slightly larger $25.5 million for the Region.
- Value Added will be about $10.9 million for the City and $11.3 million for the Region.
- The City of Sacramento will receive about 89 long term jobs, while the Region receives about 98.
- State and Local tax revenues are generated largely in the City of Sacramento, which accounts for $1.59 million of the Region's $1.64 million.
- General Fund Revenues estimates are $488,780 for the City and $507,205 for the Region.

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Economic Impacts on Specific Industry Sectors

The overall impacts on the City and the Region of the construction and operational phases of the SNGS project, discussed above, do not show the entire detail of which types of business and industry sectors benefit from the project. The tables below show specifically how the economic benefits are distributed throughout the economy.

The data in the table are Total Output (revenues to business and government entities), which include all direct, indirect, induced, and tax impacts; compensation to employees in each sector; and the number of jobs supported in each sector.

Construction Phase Sector Impacts for the City of Sacramento

NAICS Sector	Sector Name	Total Output	Employee Compensation	Employment
11	Agriculture, Forestry, Fishing and Hunting	$4,360	$791	0
21	Mining	$7,794,035	$852,453	16
22	Utilities	$16,496,883	$1,740,852	26
23	Construction	$4,129,739	$1,622,523	33
31-33	Manufacturing	$417,377	$86,639	1
42	Wholesale Trade	$681,724	$243,353	4
44-45	Retail Trade	$977,385	$358,441	13
48-49	Transportation and Warehousing	$1,931,856	$407,360	5
51	Information	$357,484	$70,892	1
52	Finance and Insurance	$903,343	$266,054	4
53	Real Estate and Rental and Leasing	$983,430	$90,601	5
54	Professional, Scientific, and Technical Services	$1,352,249	$517,720	10
55	Management of Companies and Enterprises	$175,009	$76,299	1
56	Administrative and Support	$520,690	$223,966	8
61	Educational Services	$94,959	$45,065	2
62	Health Care and Social Assistance	$1,099,521	$547,631	12
71	Arts, Entertainment, and Recreation	$90,765	$33,817	2
72	Accommodation and Food Services	$469,841	$154,477	8

The City of Sacramento sector impacts are shown in the adjacent tables, which show the one-time construction impacts and the annual operational impacts. The construction impacts are greatest in the Utilities sector, which will receive about $16.49 million in total revenues and will support 26 employee-years of work. Mining (which includes the natural gas insertion and extraction process) is second, with $7.79 million and 16 employees. Other sectors with high impacts include Construction ($4.12 million and 33 employees), Transportation and Warehousing, which includes the pipeline transportation ($1.93 million and 5 employees), Professional, Scientific, and Technical Services ($1.35 million and 10 employees), Health Care ($1.09 million, 12 employees). Retail trade will receive $0.97 million and 13 employees.

Operations Phase Sector Impacts for the City of Sacramento

NAICS Sector	Sector Name	Total Output	Employee Compensation	Employment
11	Agriculture, Forestry, Fishing and Hunting	$2,012	$382	0
21	Mining	$887,426	$49,716	1
22	Utilities	$65,934	$8,527	0
23	Construction	$238,788	$131,292	3
31-33	Manufacturing	$189,185	$36,200	0
42	Wholesale Trade	$405,375	$144,705	2
44-45	Retail Trade	$488,580	$179,152	6
48-49	Transportation and Warehousing	$12,930,092	$2,354,809	19
51	Information	$211,788	$42,156	1
52	Finance and Insurance	$573,709	$170,012	2
53	Real Estate and Rental and Leasing	$402,624	$37,617	2
54	Professional, Scientific, and Technical Services	$1,428,792	$491,367	10
55	Management of Companies and Enterprises	$59,879	$26,408	0
56	Administrative and Support	$544,113	$268,206	10
61	Educational Services	$44,012	$20,889	1
62	Health Care and Social Assistance	$525,132	$261,545	6
71	Arts, Entertainment, and Recreation	$44,429	$16,601	1
72	Accommodation and Food Services	$230,858	$75,982	4

The operations phase has an entirely different sector distribution, with the Transportation sector (which includes pipeline transportation) by far the largest, with nearly $13 million in revenues and 19 permanent jobs. The other large sectors are Professional, Scientific, and Technical Serivces; Mining (which includes the gas pumping and processing); and, in terms of employment, Administration and Support, with 10 permanent employees.

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Similar data for the Sacramento Region are shown in the adjacent tables. The sector rankings are somewhat different from the City sectors because much of the higher skilled construction inputs are provided by firms located outside the City; and because a large percentage of the employee (induced) residential and household consumption activities occur outside the City.

Construction Phase Sector Impacts for the Sacramento Region

NAICS Sector	Sector Name	Total Output	Employee Compensation	Employment
11	Agriculture, Forestry, Fishing and Hunting	$57,305	$7,952	0
21	Mining	$9,222,695	$956,186	27
22	Utilities	$32,023,954	$4,176,692	41
23	Construction	$10,167,356	$3,609,139	75
31-33	Manufacturing	$1,022,121	$185,351	2
42	Wholesale Trade	$1,028,330	$362,319	6
44-45	Retail Trade	$2,135,106	$771,695	29
48-49	Transportation and Warehousing	$3,443,583	$760,481	10
51	Information	$725,466	$142,883	2
52	Finance and Insurance	$2,070,868	$595,644	10
53	Real Estate and Rental and Leasing	$2,114,201	$163,148	9
54	Professional, Scientific, and Technical Services	$2,714,200	$1,029,564	21
55	Management of Companies and Enterprises	$347,924	$152,177	2
56	Administrative and Support	$951,403	$407,859	16
61	Educational Services	$184,452	$85,603	4
62	Health Care and Social Assistance	$2,242,007	$1,083,134	24
71	Arts, Entertainment, and Recreation	$253,003	$88,351	5
72	Accommodation and Food Services	$1,015,686	$331,355	18

Operating Phase Sector Impacts for the Sacramento Region

NAICS Sector	Sector Name	Total Output	Employee Compensation	Employment
11	Agriculture, Forestry, Fishing and Hunting	$14,554	$2,191	0
21	Mining	$393,281	$21,090	1
22	Utilities	$137,614	$20,585	0
23	Construction	$259,222	$135,656	3
31-33	Manufacturing	$280,078	$46,230	0
42	Wholesale Trade	$336,084	$118,415	2
44-45	Retail Trade	$608,483	$219,907	8
48-49	Transportation and Warehousing	$12,985,774	$2,387,337	20
51	Information	$239,533	$47,351	1
52	Finance and Insurance	$699,577	$203,051	3
53	Real Estate and Rental and Leasing	$477,205	$39,098	2
54	Professional, Scientific, and Technical Services	$1,485,589	$504,774	10
55	Management of Companies and Enterprises	$74,136	$32,426	1
56	Administrative and Support	$561,201	$269,070	11
61	Educational Services	$50,678	$23,527	1
62	Health Care and Social Assistance	$628,354	$303,647	7
71	Arts, Entertainment, and Recreation	$70,075	$24,695	1
72	Accommodation and Food Services	$287,123	$93,681	5

D2-280 (Cont.)

Researcher Qualifications

Dr. Robert Fountain
Regional Economics Consultant
1350 Hayes Street, Suite 3-c
Benicia, CA 94510
916 719 2037
Fountain@csus.edu

Dr. Robert Fountain is a regional economics consultant and *professor emeritus* at California State University Sacramento, having over 25 years of teaching and researching regional economics topics in the Sacramento Region. He has a doctoral degree from UCLA, with major field concentrations in Housing, Real Estate, and Urban Land Economics. Other fields of study include Finance, Urban and Regional Planning, and Research Methodology.

He is the Director of the Applied Research Center at Sacramento State and has also served as Chief Economist for the Sacramento Regional Research Institute and Director of the Real Estate & Land Use Institute at Sacramento State.

His research clients in the Sacramento Region have included SACTO, the Sacramento Metropolitan Chamber of Commerce, the Sacramento Housing and Redevelopment Agency, SMUD, Placer County Office of Economic Development, Folsom Economic Development Corporation, the City of Roseville, the City of Folsom, Hewlett Packard, Intel, and other private firms and builder/developer firms in the region.

Dr. Fountain's experience in economic analysis over a range of related topics such as economic forecasting, economic development, land use planning, housing market analysis, labor market and educational issues, and many others allows him to go "outside the box" and identify relationships between issues which have an integrated effect on the regional economic environment.

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APPENDIX 16

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

DIRECT TESTIMONY OF

SHAWNA ACKERMAN

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail: ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: September 5, 2008

Q1 ***Please State Your Name, Address And Occupation.***

Shawna Ackerman, FCAS, MAAA
Pinnacle Actuarial Resources, Inc.
50 California Street, Suite 1500
San Francisco, CA 94111

My occupation is Consulting Actuary.

Q2 ***Please State Your Education, Degrees.***

I have a Bachelor of Arts degree in Mathematics from Oregon State University, Corvallis, Oregon. I am a Fellow of the Casualty Actuarial Society (FCAS) and a member of the American Academy of Actuaries (MAAA).

Q3 ***Please Describe Your Career Path.***

I began my career in insurance working for the California Department of Insurance ("Department" or "CDI") for eight years from September 1989 to February 1998. My positions at the Department included Insurance Rate Analyst, Associate Insurance Rate Analyst, Associate Casualty Actuary and Senior Casualty Actuary, all of which I served in the Rate Regulation Division. As an Insurance Rate Analyst, I was responsible for reviewing insurer rate filings for all lines of property and casualty insurance subject to California's Proposition 103 (Cal. Ins. Code §1861.01 *et seq.*), which includes homeowners insurance coverage. When I was promoted to Associate Insurance Rate Analyst, I was assigned to the Deputy Commissioner of Rate Regulation to assist with special projects including assisting in the drafting of regulations necessary to implement Proposition 103. When I attained my Associate designation from the Casualty Actuarial Society ("CAS") and was promoted to Associate Casualty Actuary in 1994, I also become responsible for representing the Department in rate and rollback hearings as an expert witness. As Senior Casualty Actuary, I continued to assist in drafting regulations and was responsible for the final review of the insurer rate request before they were accepted (or recommended for hearing) by the Deputy Commissioner of Rate Regulation. Since 1998, I have been a consulting actuary and have continued working on projects involving ratemaking and loss reserving. I am an Editor of the CAS Journal, Co-Chair of the American Academy of Actuaries Committee on Extreme Events, and a prior member of the CAS Ratemaking Committee.

Q4 ***Is A True And Correct Copy Of Your Curriculum Vitae Attached As Exhibit A?***

Yes.

Q5 ***Have You Previously Provided Expert Witness Testimony?***

Yes. I provided expert witness testimony on behalf of the California Insurance Commissioner while I was employed at the California Department of Insurance as

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noted above. As a consulting actuary, I have provided expert witness testimony in matters related to ratemaking, loss reserving and the CDI prior approval process.

Q6 ***Did SNGS Engage You To Provide Your Opinions As To The Impact Of The Proposed SNGS Natural Gas Storage Facility On The Cost Of Homeowner Insurance On The Residences Over Or In The Neighborhood Of The Project?***

Yes.

Q7 ***Did You Complete Your Assignment?***

Yes.

Q8 ***What Is Your Opinion As To The Impact, If Any, Of The Construction And Operation Of The Proposed SNGS Natural Gas Storage Project On The Cost Of Homeowners' Insurance As To The Residences Over Or In The Neighborhood Of The Project?***

It is my opinion that the SNGS project will not have any impact as to cost or availability of Homeowner's Insurance as to the residences over or in the neighborhood of the SNGS Project.

Q9 ***Are You Reasonably Certain Of Your Opinion?***

Yes.

Q10 ***What Methodology Did You Use To Reach Your Opinion?***

I relied upon my experience with California rate regulatory laws and the California homeowners insurance market. I also reviewed the rating manuals for the larger homeowners insurance companies in California.

Q11 ***Is That Methodology One That Is Generally Used By Other Actuaries?***

For the question posed, the methodology that I used is what other actuaries would use.

Q12 ***Please Elaborate.***

Because California insurance law requires homeowners insurance carriers in California to file and receive approval of their rates prior to their use, a review of the filed rate manuals will indicate if there is a premium differential associated with proximity to a nature gas storage facility or something of a similar nature. In reviewing the rate manuals for the major insurers I see no indication that proximity to, or presence of, a natural gas storage facility impacts rates or premiums.

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Q13 ***Did You Contact Appropriate Representatives Of Several Major Insurance Carriers To Verify Your Conclusions?***

Yes, I did. They shared my opinion that proximity to, or presence of, a natural gas storage facility has no impact on homeowner insurance rates or premiums.

Q14 ***Does That Conclude Your Direct Examination Testimony?***

Yes.

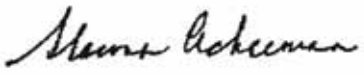
D2-281 (Cont.)

VERIFICATION OF TESTIMONY

I, Shawna Ackerman, have submitted the foregoing written testimony on behalf of Sacramento Natural Gas Storage, LLC in the Proceeding on Application No. 07-04-013. The statements made in my written testimony are true of my own knowledge, except as to matters which are stated therein on information or belief; and as to those matters, I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on October 16, 2008 at San Francisco, California.



Shawna Ackerman
Pinnacle Actuarial Resources, Inc.
50 California Street, Suite 1500
San Francisco, CA 94111

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(Cont.)

EXHIBIT A

CURRICULUM VITAE

NAME Shawna Ackerman

BUSINESS ADDRESS
50 California Street, Suite 1500
San Francisco, California 94111
Phone: (415) 439-5226
Fax: (415) 439-5228
e-mail: shawnaa@pinnacleactuaries.com

EDUCATION
OREGON STATE UNIVERSITY
Bachelor of Arts, Highest Honors – 1985
Major – Mathematics

CONTINUING EDUCATION
Estimated study time exceeding 3,000 hours necessary for completion of qualifying exams for membership in Casualty Actuarial Society (CAS)

Meet all continuing education requirements of the American Academy of Actuaries necessary to sign a public actuarial opinion

MEMBERSHIP IN PROFESSIONAL ORGANIZATIONS

Casualty Actuarial Society (CAS)	
Associate Member	1994
Fellow	1996
American Academy of Actuaries	1998
Casualty Actuaries of the Bay Area	1994

EMPLOYMENT HISTORY

Drake Office Overload	1986-1987
Jon Douglas Company	1987-1989
California Department of Insurance	1989-1998
Miller, Herbers, Lehmann, & Associates, Inc.	1998-2002
Pinnacle Actuarial Resources, Inc.	2003-present

PROFESSIONAL ACTIVITIES

CAS Examination Committee	1996-2000
CAS Committee on Review of Papers	1998-2006
CAS Ratemaking Committee	1998-2003
AAA Committee on Financial Soundness/Risk Management	2004-
CAS Dynamic Risk Modeling Committee	2004-2007
AAA Committee on Extreme Events	2006-
CAS Editorial Board	2007-

PROFESSIONAL PRESENTATIONS

Auto Rating Yardsticks, Insurance Regulatory Examiners Society

Earthquake Loss Mitigation and Insurance, Western States Seismic Policy Council, Panel Discussion

Workers Compensation Filing under Open Competition, Society of State Filers

Numerous presentations at CAS events regarding pricing and regulatory issues

EXPERT TESTIMONY

Administrative Hearings in California, Connecticut, Kentucky, Texas
Legislative Hearings in California and Oregon
Courts in California, Colorado

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(Cont.)

APPENDIX 17

S.C.64...

SMUD

SACRAMENTO MUNICIPAL UTILITY DISTRICT
The Power To Do More.℠

SNGS - 10

P.O. Box 15830, Sacramento, CA 95852-1830; 1-888-742-SMUD (7683)

February 25, 2008
AGM/ES 08-009

Presiding Commissioner Timothy Alan Simon
California Public Utilities Commission
Attn: ALJ Richard Smith
505 Van Ness Avenue
San Francisco, CA 94102-3298

CPUC PROCEEDING A0704013; SACRAMENTO NATURAL GAS STORAGE PROJECT

Dear Commissioner Simon:

This letter is to affirm the support of the Sacramento Municipal Utility District ("SMUD" or "the District") for the application of Sacramento Natural Gas Storage, LLC ("SNGS") for a *Certificate of Public Convenience and Necessity* to construct and operate a natural gas storage facility in the now depleted Florin Gas Field in Sacramento.

The SNGS project will offer the following benefits to SMUD:

- Provide about 30 days of back-up and emergency gas supply at a critical location on the SMUD pipeline. At this location it will supply gas to SMUD's gas-fired power plants in the event of any upstream disruption or curtailment for any reason such as pipeline maintenance, accident, terrorist activity, or other supply disruption on the PG&E backbone gas transmission system. These plants combined make up the majority of SMUD's average daily load.

- Permit the stockpiling of gas when lower cost supply is available and thereby avoid the need to purchase supply when gas is in high demand at higher prices.

- Provide reliable supply for "peaker plants" on the SMUD system.

- Provide gas-powered generation to back up solar, wind, and other alternative sources of power.

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For these reasons, SMUD has entered into a long term Gas Storage Services Agreement with SNGS, subject to issuance of all necessary approvals, including the *Certificate of Public Convenience and Necessity* and ultimate completion of the actual facility, all on a timely basis.

SMUD has entered into this Storage Agreement with the expectation that the Commission and other regulatory agencies will undertake a full and complete investigation to ensure that public health and safety and the environment will be adequately protected in connection with the development of the SNGS facility. We are confident that all such issues will be fully examined during the course of these proceedings and SMUD will, of course, abide by the outcome.

SMUD is hopeful that this process will be completed this year so that this much needed project can be brought on line in 2009. If you have any questions about SMUD's position in this matter, please call me personally at 916-732-6757.

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(Cont.)

Sincerely,

James R. Shetler
Assistant General Manager
Energy Supply

APPENDIX 18

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

DIRECT TESTIMONY OF

BARRY BRUNELLE

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail: ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: September 5, 2008

Q1 ***Please State Your Name, Address And Occupation.***

My name is Barry Brunelle. My physical business address is: 6301 "S" Street, Sac CA 95817, and the mail address is: P.O. Box 15830, Sac CA 95852.

Q2 ***Please State Your Education, Degrees.***

I received a degree in mechanical engineering from California Polytechnic State University, San Luis Obispo. I am a registered Professional Engineer in California.

Q3 ***Please State Your Current Employer.***

Sacramento Municipal Utility District (SMUD).

Q4 ***What Is Your Job Title?***

Supervisor, Gas Supply.

Q5 ***How Long Have You Held That Position?***

I have worked at SMUD for over 14 years; I have held my current position for in excess of the past 10 years.

Q6 ***Please Describe Your Prior Work Experience.***

My work experience is detailed in the resume that is attached as **Exhibit A.**

Q7 ***Please Describe The SMUD System.***

The Sacramento Municipal Utility District (SMUD) provides electric power to a 900 square mile service area that generally matches Sacramento County. SMUD is the sixth largest community owned electric utility in the nation in terms of customers served. The District has been providing electric service to our customer owners since 1947. Some of District's corporate highlights are: Service area population ~1.4 Million; number of customers ~600,000; peak load (record to date) 3,299 MW (July 24, 2006); number of employees 2,226 (year end 2007). The District has 695 MW of hydroelectric capacity and 995 MW of gas-based generating capacity. The remainder of the capacity necessary to meet the projected load is met with power purchases from the market.

Q8 ***Please Describe The SMUD Operating Philosophy With Regard To Reliability.***

The District has an extremely high commitment to its customer-owners. The utility is governed by its own elected Board of Directors who are devoted to managing the District. Unlike many other municipal utilities, the District is not a City department, and its rates are not comingled with the general fund. All of the revenue collected from the customers goes back to paying for the expenses of operating the utility. Therefore, our customers effectively own the utility.

Meeting our customers' energy requirements is one of the District's core values. One of the ways that the District is able to offer a high level of reliability is by maintaining local control. SMUD is not regulated by the CPUC and we are not in the California Independent System Operator Control area. This gives us a lot of autonomy and control of our operations and service to our customer-owners.

Q9 ***Please Describe How Natural Gas Fits Into The SMUD System.***

As described above, the District has 995 MW of gas generating capacity. This represents about 30% of the District's peak load. The average daily gas load on SMUD's plants is approximately 125,000 Dth/d - 130,000 Dth/d. The historical peak gas load was 161,000 Dth/d. The consequences of not delivering gas and taking such a significant portion of SMUD's total resource mix out of service could be dire.

Q10 ***Does SMUD's Perspective On Reliability Apply To Natural Gas?***

SMUD's philosophy on reliability, described above, has also been incorporated into the natural gas part of SMUD's business. The District has firm long-term transport capacity all the way to the supply basins. We also own gas reserves and we manage our own supply procurement activities. Many municipal utilities contract with a marketer to provide this type of procurement services; however, there is a loss of control when that is contracted out.

The District constructed its own 71-mile long gas transmission line to connect all of the gas generating plants to the backbone transmission system in California. The District also owns an equity interest in the PG&E backbone transmission lines going to the northern and southern California borders. By owning assets and actively managing its own system, the District is much better able to control the cost and reliability of gas, and hence the cost and reliability of power to its customer owners.

Q11 ***Please Generally Describe The Natural Gas System SMUD Currently Relies Upon.***

The District has long-term firm pipeline capacity to most of the supply basins that provide gas to California. This includes the basins in Alberta Canada, the Rocky Mountains and the San Juan basin in New Mexico. The interstate pipeline systems that access these basins are Gas Transmission Northwest, to Canada, TransCanada pipeline within Canada to the basin, Kern River to Wyoming and Transwestern Pipeline to New Mexico.

In addition to this, the District has capacity on the California intrastate system. The District owns approximately 45,000 Dth/d of capacity on PG&E's intrastate Line 401 going north and approximately 45,000 Dth/d of capacity on PG&E's Line 300 going south. We pay PG&E a monthly fee to operate our pipeline interest on our behalf; we also pay our share of the capital improvements necessary to keep the project viable. We also have contracted for long-term tariff service for an additional 20,000 Dth/d in each direction, which makes the total firm transport capacity delivered to our interconnection approximately 130,000 Dth/d. The District will continue to own the equity capacity as long as the pipeline continues to exist, and the District's long-term tariff service has a longer term than any other customer of that class.

The District purchased an interest in some gas reserves in 2003. We own approximately 25% of the "Rosa" reserve located in New Mexico. The SMUD share of this reserve was estimated to contain 150 billion cubic feet (~150 million Dth). We must pay our share of the ongoing costs to operate the project. Currently, the production is between 20,000 Dth/d to 25,000 Dth/d, which will decline over time.

The District has a diverse gas supply portfolio, which includes the gas reserves described above, and several long-term contracts, which help limit its exposure to fuel price

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volatility and excessive rate hikes. The District has the staff and systems in place to manage a gas procurement program to effectively optimize its assets.

The District currently has a contract for storage service on the Wild Goose storage facility through March 2009. The capacities are: inventory 2.25 million Dth, injection 28,500 Dth/d and withdrawal 45,000 Dth/d. The withdrawal rate is slightly less if inventory drops too low.

Q12 ***Please Describe How Gas Storage Contributes To The Gas System.***

Storage provides several key functions for the District: 1) Physical reliability; 2) Operational flexibility; 3) Insurance against extreme prices; and 4) Price arbitrage. Reliability is the most important function for SMUD. After SMUD obtains storage, it will seek to optimize its value.

For example, when prices seem excessive, SMUD may avoid a routine purchase and make a storage withdrawal instead. The benefits of storage also apply to sales opportunities. SMUD would normally have gas pre-purchased to meet our expected load. But if a plant trips off-line, we may have to make a desperation sale under some conditions, or face a penalty. Under such circumstances, having the ability to inject gas would provide us with valuable operational flexibility. There are also opportunities for making sales during stressed market conditions. Occasionally PG&E will declare an operational flow order when the pressure in the pipeline gets too high or low. When this happens, customers must make sure that they have a close match between their supply and demand or face a penalty. Some customers will pay a premium to avoid the penalty.

The proposed project will allow SMUD to withdraw gas from storage and replace it at a later time, when prices are lower. The price arbitrage feature allows the District the ability to purchase gas when it is low, store it and then withdraw it to avoid purchases (or make a sale) in the future when gas prices are high. The District buys gas, or financial contract, for up to three years in advance of delivery.

In the past, the District has more than offset its cost for gas storage by using these techniques. While we may not cover the cost every year, we expect to realize savings that will contribute to offsetting the cost of storage. In short, gas storage provides us with substantial operational efficiencies that benefit our customer-owners.

Physical reliability is crucial because approximately 85-90 percent of the gas consumed in California comes from supply basins over 1,000 miles away. Essentially 100 percent of the gas the District uses comes from these sources. The supply could be interrupted for any reason including: extreme weather (cold, hot, dry, floods, etc.), earthquakes, terrorist attack, operator error, fire, rapid demand growth, pipeline corrosion, supply problems in the basins, etc. Local gas storage provides critical back up supply for such interruptions.

Q13 ***Please Describe How The SNGS Project Provides Advantages That Cannot Be Realized From Other Natural Gas Storage Facilities.***

The critical advantage is that the SNGS project is directly connected to the District's local pipeline, near our power plants. The other natural gas storage projects are connected to the regional pipeline system, described above. Therefore, SMUD does not have as much direct control over such storage. Our storage rights in those distant

D2-284 (Cont.)

facilities may be confiscated and the gas SMUD had purchased could be diverted when SMUD needs it the most. Even though SMUD has an ownership interest in parts of the pipeline system, PG&E will confiscate and divert gas to prevent the pilot lights of residential customers from going out, which can occur if pressure in distribution centers drops too much. Some operators call this protecting its Core Customers or protecting "system integrity." They call it "system integrity" because when pressures in distribution centers drops so much that pilot lights go out, the gas operator must shut down that entire pipeline segment, purge the pipeline of air, and then relight all of the pilot lights, which could take weeks depending on how widespread the problem was. Gas companies will do almost anything to avoid this situation, and curtailing major loads, including those for power plants, is one of their most effective methods to quickly increase pressure. They will also divert gas that others have purchased, including gas in storage. Gas SMUD purchases from the Wild Goose facility is thus susceptible to confiscation and diversion. Gas stored in the SNGS facility would not be, making it a more reliable and cost effective storage option for the District.

Further, the other gas storage projects cannot protect against problems that may occur on pipeline segments located west of our power plant locations. In particular, we are very concerned about our local pipeline that is directionally drilled under the Sacramento River and the Deep Water Ship Chanel. If a problem occurred with our pipeline under these crossings, there is nothing that we could do except drill and pull a new segment of pipe. This could take weeks and the power plants would not be able to operate. Because the SNGS facility will be directly connected to our system, east of these underwater crossings, it will provide a significant level of protection against such an event.

Q14 ***Does The SNGS Project Serve SMUD's Needs More Effectively Than The Lodi Gas Storage Facility?***

Yes, cost savings is major advantage. Lodi could not provide anything approaching the benefits of the SNGS project without SMUD building a pipeline to the Lodi system. The cost and environmental impacts of such a lengthy pipeline extension would be significant. To the best of my recollection, SMUD estimated the cost of such a pipeline in 2003 and determined that it would be approximately $20,000,000 and presented numerous environmental, engineering, permitting and right-of-way challenges. Of course, the cost today would be much higher, especially given the tremendous increase in the price of steel since 2003. Aside from these economic, environmental and permitting problems, SMUD attempted to negotiate an agreement with the owners of the Lodi facility over a period of several years, but we were unsuccessful.

Q15 ***How Much Storage Capacity Will The SNGS Project Provide For SMUD and How Was it Sized?***

If cost were no object, we would like to have enough withdrawal capacity to meet our entire peak load of roughly 180,000 Dth/d to protect against a complete supply curtailment. However, because we must balance budget limitations against our resource needs, we chose a level (70,000 Dth/d) that would generally replace enough supply if one transport path (north or south) were curtailed, at least to average load levels. We have transport capacity north and south of approximately 65,000 Dth/d each way, for a total delivered capacity of about 130,000 Dth/d. Therefore, if we lost one path, the SNGS

D2-284 (Cont.)

project would allow us to meet at least our average expected load of 130,000 Dth/d utilizing the storage withdrawal capacity of 70,000 Dth/d. Storage is a bundled product, with three components; injection, withdrawal and inventory. The amount of inventory and the rate of injection are, to some degree dictated by the withdrawal rate.

Q16 ***How Have Other Utilities Designed Their Systems To Mitigate Against These Types Of Scenarios?***

In the past, many natural gas power plants in California and around the Country had dual fuel capability. Natural gas was designed as the primary fuel, with fuel oil stored on-site, in case the natural gas supply was curtailed, as back up. This made good sense and the oil was utilized on numerous occasions.

Q17 ***Is This Still An Option For California Electric Utilities?***

No, burning oil has a negative impact on air quality and power plants can no longer use fuel oil as a back-up fuel supply in California. As a result, gas utilities have changed their design criteria and practices to make more pipeline capacity available to serve loads like the power plants. However that will not protect against many of the catastrophes that have been seen in the past, or those that are occurring today in many locations around the country and the world.

Q18 ***Does The SNGS Project Provide SMUD With An Opportunity For Expanding Its Power Generation Capacity, Including The Deployment Of Renewable Energy Sources?***

Yes, the Cosumnes Power Plant was permitted for 1,000 MW; however, only 500 MW of capacity was constructed. The District could thus install peaking turbines at the plant, in conjunction with an intermittent renewable generation source, such as wind and/or solar.

The peaking plants would not run very often, but would be available in an emergency or high-need situation, such as when we dispatched a renewable resource, but for some reason it was not available.

The current capacity on the local SMUD pipeline is only capable of meeting the current peak load at the plants. Having gas storage directly on our pipeline would avoid the necessity of building additional pipeline capacity. It would be harder to justify adding additional pipeline capacity for peaking plants that would not run very often. Further, the storage would be a very good match for this type of intermittent load from a gas supply situation.

Q19 ***What Value Does The SNGS Facility Offer To SMUD Beyond Reliability?***

One of the features is flexibility of scheduling the injections and withdrawals. We can make those decisions outside the normal PG&E nominating timelines. It also may allow us to utilize load shifting on our electric system. The compressor at the site will be electric, served by SMUD. We will use off peak power on most occasions when injecting the natural gas.

D2-284 (Cont.)

Q20 ***Is The Existing Metering Equipment At The Interconnection Of Line 400/401 And Line 700 (Near Winters CA) Capable Of Measuring Accurately The Flows Anticipated In Connection With The SNGS Facility (I.E. Up To 100,000 Mcf/Day)?***

No. The existing spin meter is capable of accurately measuring flows up to approximately 212,000 Mcf/day at 722psig. SMUD loads can be as high as 170,000Mcf/day. With the addition of SNGS flows up to 100,000 Mcf/day, the combined loads of SMUD and SNGS could exceed the existing meter capacity.

Q21 ***Has SMUD Had Discussions With PG&E Regarding Updating The Meter In The Past?***

Yes. The turbine meter at Winters has failed three times since 2005. SMUD and PG&E have discussed this matter several times over the last year or so.

Q22 ***Does SMUD Believe That The Meter Should Be Upgraded?***

Yes. This would improve the accuracy and would result in fewer maintenance challenges under the existing range of deliveries at the interconnection of Line 400/401 and Line 700. Furthermore, taking into account the increased variability and range of delivery volumes that will result from the addition of deliveries to the SNGS Facility, the need for upgrading is even more compelling.

Q23 ***Has SMUD Proposed A Meter Upgrade Design To PG&E And SNGS?***

Yes. We have presented a proposed design to PG&E and SNGS. With certain potential refinements to assure the desired functionality and compliance with all industry standards and regulatory requirements, the three parties have agreed in principle to an engineering design. With the concurrence of SNGS, SMUD and PG&E are proceeding to determine the remaining detailed engineering design specifications.

Q24 ***Have SMUD, PG&E And SNGS Agreed To An Allocation Of Responsibility For The Installation Of The Proposed New Meter?***

Yes. We have agreed in principle that SMUD, as the owner of the meter station, will contract with a third-party contractor that is also approved by PG&E and SNGS to undertake the meter modifications, with supervision by PG&E.

Q25 ***Have SMUD, PG&E And SNGS Agreed To A Cost Allocation For The Meter Modifications?***

Yes.

Q26 ***Is SMUD Willing To Enter Into An Operating Agreement With SNGS For Use By SNGS Of Capacity On SMUD's Line 700 For Deliveries To And Withdrawals From The Proposed SNGS Facility?***

Yes.

D2-284 (Cont.)

Q27 ***In View Of Such Common Use Of Line 700 By SMUD And SNGS, Is SMUD Willing To Enter Into Balancing Arrangements With SNGS Such That, For The Purposes Of The SNGS Account With PG&E, The Volume Of Gas Scheduled By SNGS To Be Delivered To Line 700 Can Be Deemed By PG&E To Be The Volume Of Gas Actually Delivered?***

Yes.

Q28 ***Does This Conclude Your Direct Examination Testimony?***

Yes.

D2-284 (Cont.)

EXHIBIT A

Resume
Barry Brunelle

I have over 28 year total experience (14 SDG&E & 14 at SMUD). I have had a wide range of experience that covers many different disciplines.

Oct 1979 - Jan 1994

Experience at SDG&E
I started work at San Diego Gas and Electric Company (SDG&E) in October 1979 and had various jobs including working: in a power plant, at a gas compressor station, at an LNG facility and as a gas resource planner. I also ran the production cost models to support rate cases and established the short-term avoided cost for the company. This provided me with a strong background in the electric industry. I was an expert witness for SDG&E before the CPUC for approximately six years.

I also Developed strategies to optimize the resource portfolio, including managing the system imbalance and storage assets. I was the lead in performing risk analysis at the LNG plant, and for potential safety issues identified in the gas distributions system. I was also responsible for developing some of the policy issues that resulted from the gas deregulation that occurred during the 1980's.

Feb 1994 – Present

Developed Gas System at SMUD
I Joined Sacramento Municipal Utility District (SMUD) in February 1994. At that time there was effectively no gas supply to the District. The first power plant was completed in 1995. I participated, and in some cases the led, in the development of the entire gas function at the District. At that time there was no distinction between front, middle and back offices; we did them all. We also did all the planning, risk and reliability work that is often performed by individual sections or departments in other companies.

We obtained long-term interstate pipeline capacity on; Kern River, Transwestern, GTN, TransCanada BC & Nova, and for several years El Paso. We also negotiated a very unique ownership interest in the PG&E Backbone system. I also negotiated a long-term storage Contract with WildGoose. We have also had storage capacity on Lodi and PG&E and SoCalGas.

We developed all of the protocols required for a gas procurement program and all of the settlement processes. We incorporated technology in at the beginning and were far ahead of the industry in efficiency of operations. Some of the challenges included getting a supplier base, getting a Canadian export license, and obtaining the long-term gas supply contracts.

Gas Front-Office / Trading

One of the activities that I am responsible for is to manage the gas Trading and Scheduling operations. This includes the physical gas purchases & sales at essentially at all the supply points serving the West including; Opal, AECO, San Juan, Topock, Dagget, PG&E Citygate and Malin. We also manage imbalances and storage accounts, and all of the data supporting the operations must be tracked.

The gas is scheduled gas 365 days per year. We have completed over 40 enabling agreements with various parties to facilitate doing physical transactions. I insure that staff follows the District's Credit Policies and the Wholesale Trading Guidelines.

Structured Contracts
My group is responsible for negotiating and managing the long-term complex contracts that relate to gas issues. One example of this is the Equity Pipeline contract that we negotiated with PG&E to purchase an interest in the California Back-Bone system. By purchasing this pipeline interest for $56.4 million we save approximately $10 million per year in avoided gas transmission costs. This contract requires ongoing administration.

Another example is the current long-term pre-pay contract. This 20 year contract for 20,000 Dth/d of supply could represent a potential savings to the District of nearly $100 million. I am the representative for the JPA that was set up to facilitate this project.

Regulatory/Legal
I was the lead in the Gas Group for the regulatory issues. We have had to represent our interest in various regulatory proceedings at FERC, the CPUC, CEC and the equivalent Canadian agencies. I have personally worked with or testified before all of these agencies. I have written testimony and presented orally on the witness stand on numerous occasions.

We have been involved in over a half dozen different law suits. These have been managed primarily within our Section. I have been the principal contact/witness in several.

Gas Reserves
We were one of the first municipal utilities to obtain our own gas reserves. I participated, or led, in essentially every part of this effort. We developed criteria that met our risk requirements for a gas reserve, and then worked with an investment banker to visit over 25 Exploration and Production firms. We found one that met our criteria and then put together a team of experts, and closed the deal.

The estimated volume of the Reserve when purchased was 150 billion cubic feet. We actively manage our interest in the Rosa Gas Reserve. There are over 300 wells and about 80 royalty owners. We pay our own share of the capital and O&M costs and pay our share of the royalties.

Resource Planning

D2-285
(Cont.)

All of the gas resources the District has acquired had to be selected, sized and valued. I led this effort on essentially all of the District's gas physical assets. One example of this is the District's recent 20 year gas storage contract, which if developed will be directly connected to the District's local gas pipeline making it one of the most reliable gas supply systems in the state.

Industry/Market Expertise
I provide to the District with a knowledge-base for the gas industry. Within the District's 2,300 employees, there are few that know much about the gas industry. I maintain a repository of information and industry contacts. I have many times provided training or information about various elements of the gas business to District employees and supported the Treasury Department with presentations to potential bond holders.

Administration
There are numerous administrative duties necessary when managing issues in an industry as broad as the Natural Gas industry. Some of these include; managing staff, managing several consultant contracts and making presentations to the Board of Directors. The total gas commodity budget for natural gas for 2008 is $338 million and represents over 60% of the Department's commodity budget.

Since all of the gas delivered is to supply the power plants, the activities are closely coordinated with the Power Trading and Risk Sections. I participate in the various meetings at the staff level and have acted as the Secretary of the Executive Level (MMC) meetings for over two years.

Education
Bachelor of Science in Mechanical Engineering, from California Polytechnic State University at San Luis Obispo, Professional Engineers certification.



D2-285
(Cont.)

APPENDIX 19

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

REPLY TESTIMONY OF

BRUCE PALMER

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail: ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: diepenbrock@diepenbrock.com

Dated: October 3, 2008

I. PROFESSIONAL BACKGROUND AND OVERVIEW OF ANALYSIS

Q1 ***Please State Your Name And Business Address.***

Bruce Palmer
Ryder Scott Company Petroleum Consultants
1100 Louisiana Suite 3800
Houston, Texas 77002

Q2 ***What Is Your Current Occupation?***

Senior Petroleum Engineer

Q3 ***Please Describe Your Educational Training.***

1993 BS Chemical Engineering – Brigham Young University
2000 MS Chemical Engineering – Brigham Young University

Q4 ***Please Describe Your Career Path Up To The Present Time.***

1998 – 2000 Exxon Houston Production Office
2000 – 2002 Exxon Mobil Exploration Company
2002 – 2004 Exxon Mobil Exploration and Production Company Malaysia Inc.
2004 – 2006 Exxon Mobil Production Company
2006 – Present Ryder Scott Company

Q5 ***How Long Have Your Worked For Ryder Scott?***

Approximately 2 years and 8 months.

Q6 ***Please Describe Your Work Experience That Is Related To Analyzing Natural Gas Storage Facilities.***

The skills required for the analysis of natural gas storage are similar to those used for analyzing natural gas production. From 1998 – 2000, I was the reservoir engineer in charge of several natural gas fields in East Texas. From 2000 – 2002, I was a technical consultant on reservoir simulation for Exxon Mobil fields throughout the world, many of which were gas fields. From 2002-2004, I was a reservoir simulation consultant for Exxon Mobil fields specifically in the Asia-Pacific region, several of which were gas fields. From 2004 – 2006, I was on a team of engineers performing simulation work on the North Field in Qatar, which is the largest non-associated gas field in the world. After joining Ryder Scott, I performed simulation work on several natural gas fields. I am currently the lead engineer on the Junction Natural Gas Storage project in the West Summit field for the Chestnut Ridge Gas Storage Company (a partnership of eCORP and Tenaska, Inc.).

D2-286

Q7 ***Is A True And Correct Copy Of Your Resume Attached As Exhibit A?***

Yes.

Q8 ***You Performed Work For SNGS Regarding The Proposed Natural Gas Storage Facility, Correct?***

Yes.

Q9 ***Please Describe In General Terms The Work You Performed For SNGS.***

I initially gave an opinion letter on the feasibility of using the Florin field for gas storage operations. Next I constructed a simulation model to predict the behavior of the Florin field during gas storage operations.

Q10 ***In Performing That Work, Did You Draw On The Expertise Or Experience Of Others At Ryder Scott?***

Yes.

Q11 ***Please Elaborate.***

The project involved the following individuals throughout the entire process. The general tasks that they performed are also listed here.

a. Mr. Jon LaFreniere, Geophysicist/Geologist – Initial geological and geophysical review. Constructed geological model.
b. Mr. Stephen Philips, Geophysicist/Geologist – provided some input for geological model construction.
c. Mr. Merrick Mainster, Geological Technician – Assisted with 3D model construction using Petrel.
d. Mr. Rick Richardson, Geologist – Assisted with well log interpretations.
e. Mr. George Dames, Geologist – Managing Sr. VP in charge of the RSC geological staff. Provided additional interpretation and insight to the geological model construction.
f. Mr. Dean C. Rietz, Petroleum Engineer – Managing Sr. VP in charge of the RSC simulation group and my immediate supervisor, provided general guidance and coordination of involved individuals.
g. Mr. D. Ronald Harrell, Petroleum Engineer, Retired from RSC– Provided some general insight as questions came up.
h. Mr. Roly Simangunsong, Petroleum Engineer – Provided assistance with tubing table generation.

D2-286 (Cont.)

Q12 ***Does Ryder Scott Maintain Records Showing The Amount Of Time Its Team Has Devoted To This Project For SNGS?***

Yes. We maintain detailed records of our time spent on this matter because our billings to SNGS are based in part on the amount of time we spend working on this matter.

Q13 ***What Is The Total Number Of Hours That Ryder Scott Has Spent Working On This Project For SNGS?***

As of August 31, 2008, Ryder Scott had spent 2066 hours of time on Geology and Engineering for this project. This figure does not include any work by our technical analysts performing data entry and similar tasks.

Q14 ***In Performing Its Work For SNGS, Did Ryder Scott Employ Standard and Accepted Methodologies?***

Yes.

II. TESTIMONY OF JOHN O. ROBERTSON

Q15 ***Have You Read The Rebuttal Testimony Of John O. Robertson, Which Was Submitted On Behalf Of Avondale Glen Elder Neighborhood Association?***

Yes.

Q16 ***Did Mr. Robertson Identify Any Errors In Your Analysis Of The Florin Field That Give You Reason To Modify The Surface Boundaries You Delineated For The Florin Field?***

No.

Q17 ***Dr. Robertson Implies That Ryder Scott Relied On The Work Of John Matthews; Can You Clarify To What Degree, If Any, You Relied On Mr. Matthews's Work.***

As discussed more fully below in Question No. 65, Ryder Scott relied on Mr. Matthews only with respect to adjusting the total volume of produced gas from the records listed on the DOGGR website. Ryder Scott did not rely on Mr. Matthews in any other way. It is my understanding that SNGS engaged Mr. Matthews to perform an early assessment of the depleted Florin gas field to determine whether it would be suitable for gas storage operations. Mr. Matthews performed this initial assessment using analytical equations. A significant drawback of such equations is that they use simplifying assumptions, which can limit their applicability to complex, real-life situations. For example, the

D2-286 (Cont.)

analytical equations Mr. Matthews used did not account for the pressure and volume effects of water migrating into the gas-bearing portion of the reservoir. Ryder Scott reviewed Mr. Matthews work, but did not rely on it. SNGS instructed us to perform, and we did perform an independent and detailed analysis of the Field to determine its functionality for gas storage operations. Our work took into full consideration the pressure and volume effects of water migrating into the reservoir.

A. HISTORY OF GAS PRODUCTION AT THE FLORIN FIELD

Q18 ***Do You Agree With The Following Statement That Appears On Page Three Of Dr. Robertson's Testimony Regarding The History Of Gas Production At The Florin Field?***

> [D]ata at the Division of Oil, Gas & Geothermal Resources (DOGGR), reveal that ... [the Florin field's 7] wells produced 8.69 MMSCF (million standard cubic feet) gas – or about 77 MCF (1000 cubic feed) converting the volume back to the reservoir conditions of 1668 psi, and 6.5 MMCF water for a total of 6.6 MMCF voidage (gas plus water) under reservoir conditions.

No. The statement includes several errors. Dr. Robertson specifies the wells produce 8,690,000 standard cubic feet of gas (i.e., 8.69 MMSCF). That number is incorrect. The correct number is 8.28 Bscf (BILLION standard cubic feet), i.e., 8,280,000,000 standard cubic feet. This significant error calls all of Dr. Roberson's calculations involving volume into question. Dr. Robertson carries this error through subsequent numbers as evidenced by his assertion that this is 77,000 cubic feet in reservoir conditions. This appears to be more than just a unit error in that he believes that the equivalent of 6,500,000 cubic feet of water volume in the reservoir was produced along with 100,000 cubic feet of gas volume for a total of 6,600,000 cubic feet voidage, which is glaringly wrong. Dr. Robertson's 6,500,000 cubic feet produced water number comes from his erroneous water production figure of 1,130,000 barrels, which is refuted in Q64.

According to Ryder Scott's simulation model, the appropriate value for the produced volume of gas at reservoir conditions is approximately 62,880,000 cubic feet, or 11,200,000 reservoir barrels. The appropriate value for the produced volume of water at reservoir conditions is approximately 105,900 reservoir barrels. Please note that the fraction of voidage volume attributable to produced water, which is given by the following equation:

$$105{,}900 \text{ rb}/[11{,}200{,}000 \text{ rb} + 105{,}900 \text{ rb}]$$

D2-286 (Cont.)

is approximately 1% and essentially negligible. This directly contradicts Dr. Robertson's subsequent conclusion, at pages 7-8 of his testimony, that produced water has a substantial effect on voidage.

Q19 ***By Way Of Background, Please State When Natural Gas Was First Produced From The Florin Field.***

July 1980.

Q20 ***For How Long Was Gas Produced From The Field?***

Approximately 7 years.

Q21 ***Was Any Natural Gas Left Inside The Field After Production Ceased In July 1987?***

Yes.

Q22 ***Approximately How Much Gas Was Left In Place?***

Approximately 5.6 Bscf.

Q23 ***How Did You Determine That Figure?***

That figure was the amount of gas left in the reservoir after matching historical rates and pressures during production using a numerical reservoir simulation.

Q24 ***Is That Methodology One That Is Generally Used In Your Field?***

Yes, for complex problems requiring reservoir simulation.

Q25 ***Are You Confident That Your Simulation of the Florin Reservoir Produced A Reasonable Assessment of the Amount of Gas Left In Place?***

I am confident in the 5.6 Bscf figure. Reservoir modeling is one of the more precise tools we use, and the 5.6 Bscf figure for the amount of gas left in place was produced after we achieved a good history match for the Florin field.

B. FIELD PRESSURES

Q26 ***Was The Gas In The Florin Field Under Pressure Before It Was Produced Beginning In July 1980?***

Yes.

Q27 ***How Do You Know That?***

From records of measured shut-in pressure for the Unocal Florin #2 well.

D2-286 (Cont.)

Q28 ***What Was The Field's Pre-Production Pressure?***

The first measured pressure was 1,668 psia (pounds per square inch absolute) at a measured depth of 3,895 feet (corresponds to a true vertical depth of 3,493 feet measured from sea level). This measurement was made in November of 1980 after a small amount of production (approximately 110 million standard cubic feet). The pressure of the field before production would be within 0.5 % of this number.

Q29 ***How Did You Determine That?***

From the record previously cited and an observation of the measured shut-in pressures versus the reservoir pressure during simulation.

Q30 ***Does The Document Attached As Exhibit B, Accurately List The Recorded Bottom-Hole Pressure For One Of The Florin Field Wells Between 1980 And 1987?***

Yes.

Q31 ***Why Did The Florin Field's Bottom Hole Pressure Decrease Between 1980 And 1987?***

The pressure dropped as gas and water was produced (removed) from the reservoir.

C. CHARACTERISTICS OF THE FLORIN FIELD

Q32 ***Dr. Robertson Challenges The Field Modeling You Performed; Before We Further Discuss His Various Criticisms, Please Describe In General Terms How You Developed That Model.***

First, the geologic model was imported into a reservoir simulation program to set the structure (size and shape) of the reservoir. The model of the reservoir is divided into discrete grid cells at this point. The location of the historical wells in the grid was specified. The physical properties of the gas, water, and reservoir rock were specified, along with how those properties vary with changes in pressure. The initial state of the reservoir before production was set in the model by specifying the initial pressure at a depth, the initial gas-water contact depth, and the initial saturations of gas and water both above and below the contact. The model was then populated with the gas volumes initially in place before production. At this stage the model was considered initialized and the volume was compared to the volume determined by the geologist for a quality check. Next, the model was tuned and calibrated by performing a history match. A history match is where historical gas production volumes are removed from the reservoir at the well locations, and the properties of the reservoir (typically permeability or aquifer strength) are adjusted to match the historical measured pressures. The history matched model was then used to run prediction scenarios.

D2-286 (Cont.)

Q33 ***Does the Method Described Above Used In Developing The Model Follow Methods That Are Generally Accepted In Your Field?***

Yes.

Q34 ***Does The Document Attached As Exhibit C, List The Pertinent Parameters You Developed For The Model?***

Yes.

Q35 ***What Do The Model Dimensions, Listed As IxJxK, 137 X 180 X 16, Mean?***

This means that the entire model grid is composed of 137 columns of grid cells in the I direction (typically the east-west direction), 180 rows of grid cells in the J direction (typically the north-south direction), and 16 layers of grid cells in the K direction (depth).

Q36 ***Please Explain What You Mean By The Number Of Active Grid Cells.***

Usually not all of the grid cells encompassed in the I, J, and K direction are required to emulate the size and shape of the reservoir. Therefore, those which are not needed are de-activated. The remaining grid cells are the active grid cells.

Q37 ***Please Explain The Significance Of The Model Porosity Figure, Which Is Listed As 31 Percent.***

Porosity is a measure of the void space in the reservoir rock available to hold reservoir fluids (gas or water in this case). A porosity of 31 percent means that in a cubic foot of reservoir, 69 percent of the volume is rock and 31 percent is open void space. This void space is distributed in some way throughout the entire cubic foot of volume. In the case of the Florin field, the porosity was estimated by the geologist from analyzing well log data.

Q38 ***Please Explain The Horizontal Permeability Figure Of 30.0.***

Permeability is a measure of the reservoir rock's conductivity to fluid flow. The more connected the void space in the rock is, the more easily reservoir fluids will flow through the rock when subjected to a pressure difference. Horizontal permeability refers to the conductivity of flow in the horizontal direction. Permeability is measured using laboratory analysis of core samples. One core analysis report of permeability at various depths for the Florin field was used as a base guide to adjusting the permeability value during the history match. The value used in the model of the Florin field in order to achieve a reasonable history match was 30 md (milli-darcies).

Q39 ***Please Explain The Rock Compressibility Figure Listed Of 6.0.***

Rock compressibility is a measure of how the pore volume changes with pore pressure (i.e., how much pore volume increases with an increase in pressure, or

D2-286 (Cont.)

conversely how much pore volume decreases with a decrease in pressure). The compressibility of 6.0 x 10^{-6} 1/psi (or 6.0 microsips) was estimated for the Florin field, which is a typical value for a sandstone reservoir of this lithology and/or porosity. Compressibility is usually measured in the laboratory using core samples. No compressibility analysis was found for the Florin field.

Q40 ***How Did You Determine The Initial Reservoir Pressure Of 1,668 Psi?***

The first measured pressure in the Florin field was 1,668 psia (pounds per square inch absolute) at a measured depth of 3,895 feet (corresponds to a true vertical depth of 3,493 feet measured from sea level). This measurement was made in November of 1980 in the Florin Unocal #2 well. Please note that pressure increases with increasing depth in the reservoir, so any cited pressure value requires a corresponding reference depth.

Q41 ***The Reservoir Temperature Is Listed In Table 1 As 97° Fahrenheit; How Did You Determine That Figure?***

Reservoir temperature was measured during well logging operations and recorded on the well logs.

Q42 ***How Does The Field Temperature Impact Behavior Of The Reservoir?***

Temperature (together with pressure) affects the physical properties of the gas in the reservoir, such as density, viscosity, etc. These properties dictate how the gas will flow in the reservoir when subjected to a drop in pressure.

Q43 ***Initial Gas-Water Contact Is Listed As 3,795; What Does That Mean?***

The dome-shaped structure of the reservoir is filled with natural gas plus a small amount of residual (immovable) water from the top of the dome down to a depth of 3,795 feet measured from sea level. Beneath this depth, the dome structure is filled with water. This depth defines the interface between the gas-filled and water-filled parts of the reservoir.

Q44 ***Please Explain How The Depth Of Initial Gas-Water Contact Is Pertinent To How The Reservoir Model Behaved In Your Analysis.***

The depth of this contact, together with the dome-shaped structure of the reservoir, determines the initial volume of gas held in the reservoir.

Q45 ***Please Explain The Significance Of The Gas Effective Relative Permeability End Point Figure Listed In Exhibit C.***

The permeability number discussed previously (30 milli-darcies) applies to one-phase flow in the reservoir (for example, all water) and is called the absolute permeability. When there is more than one phase in the reservoir, such as gas together with water (as in the Florin field), the effective permeability for each

D2-286 (Cont.)

phase is reduced (because the phases are "competing" to flow through the same space). The effective permeability of the gas is found by multiplying the absolute permeability times a fraction. This fraction is a function of the gas saturation. The "end point" refers to the highest fraction of the absolute permeability possible, which occurs when gas is present with the lowest water saturation possible (sometimes called immovable water). In other words, in the presence of the lowest water saturation possible (33 %), gas will flow with a maximum effective permeability which is 80% of the absolute permeability of 30 milli-darcies, which is 24 milli-darcies.

Q46 ***Please Explain The Significance Of The Water Effective Relative Permeability End Point Figure Listed In Exhibit C.***

The same discussion above applies for water flowing through porous rock in the presence of gas.

Q47 ***Please Explain The Trapped Gas Saturation Figure Listed In Exhibit C.***

As the Florin field produced gas, water slowly encroached up above the original gas water contact from aquifers. When water sweeps through rock that has a high saturation of gas, part of the gas becomes trapped as water fills and seals up the more narrow connections between the void spaces. Using experimental correlations developed by Katz (1966), it is estimated that for a rock with 31% porosity, 22% of the gas will be trapped by encroaching water.

Q48 ***You Listed A Gas Gravity Of 0.598; What Does That Mean?***

This number represents the density of the gas in the reservoir divided by the density of air when both densities are measured at standard conditions (14.7 psia and 60 F). This number means that the density of the gas from the Florin field is 59.8% of the density of air at standard conditions.

Q49 ***How Did You Determine That Gas Gravity Value?***

This figure is taken from records kept by the original operators of the field.

Q50 ***Please Explain The Last Line Of Exhibit C, Model OGIP, Which Is Listed As 13.8.***

OGIP stands for 'original gas in place', which means the total volume of all the gas in the reservoir prior to production. The volume of gas initially in place in the Florin field is calculated by the model to be 13.8 billion cubic feet of gas at standard conditions.

Q51 ***Are You Confident That The "Pertinent Model Parameters" Listed In Exhibit C Reasonably Describe The Florin Field?***

Yes.

D2-286 (Cont.)

Q52 ***Please Explain Why.***

These parameters are the result of simulation work which achieved a reasonable history match.

Q53 ***Does The Florin Field Have Any Aquifers That Were Relevant To Your Analysis?***

Yes.

Q54 ***Please Describe These Aquifers.***

An aquifer is a large water-bearing body of sand connected to the reservoir which supplies an influx of water as gas is produced.

Q55 ***How Are These Aquifers Relevant To The Analysis You Performed?***

The aquifers provide pressure support and explain the encroachment of water and subsequent watering out of the historical gas production wells.

Q56 ***Does The Document Attached As Exhibit D, List The Relevant Properties Of The Aquifers?***

Yes.

Q57 ***Please Explain What The Listed Properties Mean.***

For the purposes of simulation, an analytical model of the water body attached to the gas bearing reservoir is described by various parameters. For the Florin field, the gas volume is essentially positioned on top of the body of water whose pressure support and influx are calculated using an aquifer model. The aquifer will exhibit certain influence on the gas accumulation, as a result of production operations. The properties listed in Exhibit D are used to define various aspects of the aquifer model, such as the relative size, shape, and flow properties. The porous rock in the reservoir is connected to the porous rock in the aquifer, so that as gas is produced from the reservoir water flows in from the aquifer. The reservoir pressure and water rates in the Florin field were matched using two aquifers attached at different locations to the bottom of the reservoir – a thicker aquifer was required in the southern area to match high water rates.

Q58 ***How Did You Determine The Values Listed In Exhibit D For Each Of The Aquifers?***

The properties of the aquifers were adjusted during the history match phase of the model in order to match the observed reservoir pressures, water arrival times, and water production rates.

D2-286 (Cont.)

Q59 ***Are You Confident That The Values Listed In Exhibit D Reasonably Describe the Florin Field's Aquifers?***

Yes.

Q60 ***Why Is That?***

For the same reason I am confident regarding the other aspects of our modeling work: the aquifer parameters are the result of simulation work which achieved a reasonable history match.

Q61 ***Did SNGS Give You Any Operational Assumptions To Use In Your Modeling Analysis?***

Yes.

Q62 ***Describe The Assumptions Upon Which Your Most Current Analysis Rests.***

During injection, the maximum pressure allowed at each well head is 1,650 psia, and the maximum rate of injection field-wide is 100 million standard cubic feet per day. During production, the minimum pressure allowed at each well head is 650 psia, and the maximum rate of production field-wide is 200 million standard cubic feet per dav

C. ASSUMPTIONS CHALLENGED BY DR. ROBERTSON

Q63 ***Did Ryder Scott Rely On The Work Of Reid, Which Dr. Robertson Discusses In His Testimony?***

No. Ryder Scott is not aware of any study by Reid. As discussed more fully in the accompanying testimony of George Dames, it appears that Dr. Robertson may have been referring to a report authored by Garrison.

Q64 ***Please Respond To Following Assertion By Dr. Robertson On Page Six Of His Testimony:***

> [T]he mathematical assumptions required to make such a model do not reflect the actual conditions that exist in the reservoir. The fact that history matching (adjusting the output so that it reflects the production of a well) must be made to make the answers more realistic support this contention.

Dr. Robertson's assertion reflects a misunderstanding of fundamental reservoir modeling processes. In reservoir simulation engineering, the matching of history helps to validate the interpretations and the assumptions that are built into the model. History matching is not "adjusting output." We followed standard

D2-286 (Cont.)

engineering procedures whereby input parameters (e.g., such as permeability, porosity, and relative permeability) are adjusted within reasonable bounds in order for the model's calculated output values (e.g., such as reservoir pressure and water flow rates) to reasonably represent observed field behavior. We disagree that there is either insufficient data or inappropriate mathematical assumptions, and the history match that was achieved with our Florin model supports this.

Q65 ***Please Respond To The Following Assertion Found On Page Three Of Mr. Robertson's Testimony:***

> There are typographic, mathematical and methodological errors in the calculation of produced gas for the Ryder Scott Company computer model. Specifically, Ryder Scott's model used a produced gas value of 8.14 MMSCF (summation of cumulative gas column for each well, SNGS 1167) while John Matthews' computation showed 8.8 MMSCF gas production. It is inexcusable that there is over an 8% difference between their numbers for the same measurement. What's worse is that neither number is correct. The well water production used by both proponents also shows similar inaccuracy and carelessness.

Ryder Scott agrees with Dr. Robertson that the cumulative gas volume produced from the field "is basic data and there should be no differences if one is not careless and carefully checks his work." In fact, the calculation of the cumulative gas volume is a simple summation of the monthly gas volumes for each well from the DOGGR database, available from the DOGGR website. According to the DOGGR database, the cumulative volume produced from the Florin field is 7.9 BSCF (billion standard cubic feet). This is the number initially calculated by Ryder Scott, which did not agree with the 8.28 BSCF number used by John Matthews in his calculations. Subsequent discussion with John Matthews and Jim Fossum indicated that several months of gas production data for several of the wells was missing from the DOGGR database. Corrected gas production rates from the client were accepted by Ryder Scott. (For simulation work conducted by Ryder Scott, the client is responsible for identifying the most valid set of data). The value of 8.28 BSCF was subsequently used in all of Ryder Scott's modeling work.

Dr. Robertson's figures regarding the gas volumes produced from the field are incorrect. First, the cumulative gas volume for the Florin field according to the DOGGR dataset is 7.9 BSCF, *not* 8.69 MMSCF, as Dr. Robertson claims. Second, the corrected cumulative gas volume for the Florin field used by John Matthews in his calculations was 8.28 BSCF, *not* 8.8 MMSCF, as Dr. Robertson claims. Third, the cumulative gas volume for the Florin field that Ryder Scott

D2-286 (Cont.)

used in its modeling work is the figure of 8.28 BSCF cited above, *not* the 8.14 MMSCF figure Dr. Robertson cites. It is thus Dr. Robertson who carelessly calculated the cumulative produced gas volumes for the Field, not Ryder Scott.

The same is true for the amount of water produced from the Field. According to the DOGGR database, a simple summation of the monthly produced water volumes for the wells in the Florin field, shows that the cumulative water produced from the field is 141,344 barrels, *not* the 1,130,000 barrels cited by Dr. Robertson at page 7 of his testimony.

Given the great emphasis Dr. Robertson places on correctly accounting for the effect of water production on field behavior (which Ryder Scott has done), it is notable that there is a 7 fold overstatement, or an approximate error of 700% in the value Dr. Robertson includes in his testimony.

Q66 ***Please Respond To The Following Assertion Found On Page Seven Of Mr. Robertson's Testimony:***

> An approximate reduction to reservoir conditions of the produced volume of gas (treating it as an ideal gas) as recorded by the DOGGR is 76.6 MCF (14.7/1668) ignoring temperature, real gas conditions, and compressibility changes. The produced water volume is nearly incompressible and so the DOGGR value of 1.13 MMB water can be approximated as 6.31 MMCF (1.13 x 5.61). This gives a total pore volume of 6.39 MMCF that was removed from the reservoir. Although these are only approximate values, it appears that more fluid was removed from the reservoir dome than it likely could have held (which also could be in agreement with Ryder Scott Company's 4th point, SNGS 1189).

The calculations in the paragraph are based on either incorrect units or incorrect values as previously discussed. Dr. Robertson's gas volumes are excessively low and his water volumes are erroneously high. When adding these volumes (at reservoir conditions) together, he performs a serious calculation error, not just a mistaken assignment of units. The propagation of his earlier errors has culminated in an estimation of an excessively low pore volume of 6.39 MMCF that was removed from the reservoir. This also allowed him to inappropriately draw conclusions concerning the effects of water in the Florin field.

D2-286 (Cont.)

Q67 ***Is Dr. Robertson's Assertion That "There Is Very Poor Vertical Permeability As A Result Of The Layers Of Shale" Accurate?***

Ryder Scott's modeling analysis did *not* reveal the existence of shale barriers that would impede gas flow below the field's cap rock. Our history-matched model analysis demonstrated that it is unlikely that there are any barriers extending across the entire field that would limit vertical flow to the top 10 feet of the interval. Our dynamic model showed good vertical permeability. Stated differently, our modeling work fairly ruled out this basis upon which Dr. Robertson seeks to expand the field's surface boundary "footprint."

Q68 ***Dr. Robertson Criticizes Ryder Scott For Supposedly Only Considering The Data From One Of The Field's Wells, Union Florin #2. Is It True That Ryder Scott Analyzed Data From That Single Well Only?***

No. As detailed in our reports, the final modeling work we performed used data from all five wells for which production history is available. An initial first pass assessment of the field behavior focused on the Union Florin #2 because it is the only well in the field that has measured shut-in bottom hole pressures (in addition to production volumes and flowing well head pressures).

Q69 ***Please Elaborate On Your Initial Assessment And Why You Performed Follow-Up Modeling Work Using Data From All Five Wells.***

In our initial independent assessment, we decided to build a radial one-well segment simulation model instead of using analytical equations to better determine the effect of the influx of water into the field. This segment model was able to reasonably match observed shut in bottom hole pressure measurements, water production rates, and flowing well head pressures for the Union Florin #2 well. This initial modeling work supported two conclusions: (1) the Florin field is a partial water drive gas reservoir (water is migrating into the reservoir from an aquifer, providing pressure support); and (2) a history-matched full field simulation model would be needed to reasonably predict the field behavior under gas storage conditions. These are the only results we relied upon from the one-well segment simulation model. Dr. Robertson seems to believe that the segment model is the basis of our subsequent modeling work. It is not. Our subsequent history matched full field model was developed using all of the historical wells in the field and their respective measured gas rates, water rates, and flowing well head pressures.

D2-286 (Cont.)

Q70 ***Dr. Robertson Is Critical Of The Decision To Not Place Any New Wells In The Area Near The Old Union Florin #2 Well; Can You Explain Why No New Wells Will Be Placed Near That Location?***

Dr. Robertson implies that it is suspicious that prospective injection wells are not planned in the area near the Union Florin #2 well, which we used for the segment model. No new injection wells will be located in this area because the northeastern side of the field has less sand above the original water contact than on the southwestern side (i.e., the clean sand is thicker on the southwest and thinner on the northeast). Injecting gas on the northeastern side carries a greater risk of pushing gas below the original water contact and losing that gas due to trapped gas in the water.

Q71 ***Please Respond To The Following Assertion By Dr. Robertson:***

> [T]he Ryder Scott Company does state that the section of the reservoir containing Florin #2 does not perform the same as the portion of the Florin field that will serve as the gas storage project, which leads to only one conclusion, they are not the same as so the model is flawed.

It appears that this statement is based on Dr. Robertson's incorrect assumption that the area containing the Union Florin #2 is not in communication with the area to be developed for the storage project, and that only the Union Florin #2 well is incorporated into the model. All wells that historically produced gas from the Florin field, and the entire reservoir volume, along with historically observed pressures and produced volumes were properly incorporated into the model. We believe that Dr. Robertson's premise that the model is flawed is based on his incorrect perceptions. In any case, all the wells in the Florin field exhibited their own unique performance to some degree. The fact that the history matched full field model was reasonably able to reproduce all this performance supports the robustness of the model.

Q72 ***Dr. Robertson Asserts That "Gas Has A Much Higher Viscosity Than Oil Or Water;" Is That An Accurate Statement?***

No. The opposite is true. Gas has a much lower viscosity than oil or water. The exact viscosity of oil, water, or gas depends on temperature, pressure, and composition. "The Properties of Petroleum Fluids," by William D. McCain Jr. (copyright 1990 PennWell Publishing Company) is a recognized authority on this subject. On page 182, McCain has a figure (Figure 6-8, Adapted from Carr, et al., Trans. AIME, 201, 997) for natural gas viscosities. This figure shows that at atmospheric pressure for natural gases with molecular weight in the range of 10 –

D2-286 (Cont.)

60 or specific gravity in the range 0.5 to 2.0 and temperatures up to 400 degrees Fahrenheit, gas viscosities range from approximately 0.0065 to 0.016 centipoise.

On pages 330 and 331, Figures 11-13 and 11-14, McCain shows that at atmospheric pressure for oils with stock tank gravity ranging from 10 – 50 API, temperatures from 100 – 300 degrees Fahrenheit, and solution gas-oil ratios ranging from 0 – 2000 scf/STB, oil viscosities range from approximately 0.15 to 200 centipoise.

On page 457, Figure 16-16, McCain shows that at atmospheric pressure for water with sodium chloride content ranging from 0% - 26% and between temperatures of 40 – 400 degrees Fahrenheit viscosities range from 0.1 to 2.1 centipoise.

L.P. Dake in his textbook "Fundamentals of Reservoir Engineering" (1978, Elsevier), which is commonly used for basic petroleum engineering courses, states on page 47: "typically, gas viscosity in the reservoir is about fifty times smaller than for liquid oil."

Q73 ***Is Dr. Robertson Correct In Asserting That Ryder Scott's Analysis Is "Based Upon A Depleted Reservoir, Not A Water Drive Reservoir With Strong Water Influx; As Such, The Data And Method, Cannot Be Relied Upon"?***

No. As discussed above, our model incorporates an active aquifer whose influence was determined through the history matching process. Our modeling indicates that there is water influx (water drive) which we would characterize as moderate. Regardless of the degree of characterization of the influx, our model and our conclusions incorporate the effects of water influx.

Q74 ***Is Dr. Robertson Correct In Stating That "A Low 14-40 Percent Ultimate Recovery Or Displacement For Solution Gas Drive Reservoirs (Pg. 365) Or 20 To 30 Percent Ultimate Recovery For Gas Cap Drive (Gas Displacement Of Oil/Water)."***

No. Dr. Robertson takes these figures from a book by Robert Mannon, but the recovery figures cited from that book apply to ***oil*** reservoirs, ***not gas*** reservoirs. The 63 percent recovery rate figure we calculated is perfectly reasonable for the Florin field and is consistent with the recovery rate for other partial water drive gas reservoirs. Howard B. Bradley, et al. in their reference manual "Petroleum Engineering Handbook" (1987, Society of Petroleum Engineers) states on page 40-26, "Typical [recovery] factors range from 50 to 70% for water-drive gas reservoirs as compared with 70 to 90% for expansion-drive gas reservoirs."

D2-286 (Cont.)

Q75 ***Do You Agree With Dr. Robertson's Assertion That Your Analysis Supports "An Even Higher Value For Recovery Of 83% Which Is Unrealistic"?***

No. The basis for this conclusion by Dr. Robertson is unclear, but he appears to have combined the recovery rate of 63 percent with the 22 percent we specify as the trapped gas saturation. Dr. Robertson incorrectly refers to this as "irreducible" gas. Trapped gas occurs only when and where water encroaches into gas-filled areas, or gas is pushed down below the original water contact. Part of the gas in these situations becomes trapped and is unable to flow to the wells. Ryder Scott's model accounts for the trapped gas; therefore the 63% recovery previously cited accounts for the trapped gas saturation.

D. SURFACE BOUNDARIES OF THE FLORIN FIELD

Q76 ***Before Turning To Dr. Robertson's Criticism of Your Delineation of the Florin Field's Surface Boundaries, Please Describe How You Established Those Boundaries.***

We worked from the intersection of the gas-water contact established in our model. More specifically, the boundary was determined by the intersection of the depth of the top of the dome-shaped reservoir structure as represented by the geologic model with a horizontal plane with a depth of 3,795 feet measured from sea level representing the gas water contact. Preliminary work by Ryder Scott used a slightly deeper value of 3,800 feet which was more conservative.

Q77 ***Does The Document Attached As Exhibit E, Show The Surface Boundaries You Determined For The Florin Field?***

Yes.

Q78 ***What Is Your Degree of Confidence In The Surface Boundaries Ryder Scott Delineated For The Florin Field?***

The surface boundaries delineated for the Florin Field represent our best estimate of the subsurface area as determined by our geologist. The boundaries are translated to the surface as part of our work and are supported by our simulation work where we achieved a good history match.

Q79 ***Do You Agree With Dr. Robertson's Criticism That Mr. Matthews Should Have "Decreased The Thickness Of The Reservoir To 10 Feet And Increased The Footprint By A Factor Of 2.5"?***

No. Dr. Robertson bases this conclusion regarding the thickness of the gas sands on the fact that on average only the top 10 feet of the wells penetrating into the sands were perforated. This argument fails to take into consideration the common industry practice to perforate wells at the upper reaches of the reservoir in order to minimize water production (e.g., water coning). It is well known that substantial

D2-286 (Cont.)

gas volumes can be produced from below the perforations where, as in the case of the Florin field, the gas sands are thick and there is good vertical communication throughout the reservoir. Gas producers commonly avoid perforating the productive interval close to the water contact to avoid producing large volumes of water. Accordingly, Dr. Robertson's contention that perforation thickness defines sand thickness is incorrect.

Q80 ***Is Dr. Robertson Correct When He States At Page Six Of His Testimony That "Only An Average Of 10 Feet Of The Upper Interval Has Ever Been Produced By The Oil Companies"?***

No. Dr. Robertson's contention that perforation thickness defines sand thickness is incorrect. Vertical communication in the Florin field allows wells to drain volumes below the 10 foot perforated interval.

E. OPERATIONAL FIELD PRESSURES

Q81 ***Before Addressing Dr. Robertson's Criticism of Your Assessment of Reservoir Pressures, Please Describe The Conclusions You Reached Regarding The Maximum Pressure The SNGS Reservoir Will Apply To The Cap Rock When Operated With A Maximum Well Head Pressure Of 1650 Psi.***

According to our model, the pressure in the reservoir adjacent to the cap rock will never exceed the initial pressure seen by the cap rock by more than 8%.

Q82 ***How Did You Reach That Conclusion?***

The history matched model was used to run a prediction scenario to calculate the pressure in the uppermost layer of the model.

Q83 ***Does The Letter, Dated June 30, 2008 And Attached Hereto As Exhibit F, Describe Your Analysis Of The Maximum Pressure The SNGS Reservoir Will Exert On The Cap Rock During The Facility's Operation By SNGS?***

Yes.

Q84 ***Please Summarize What You Determined From That Analysis.***

As detailed in the letter, we determined that the maximum pressure the reservoir will exert on the cap rock will never exceed approximately 1,805 psia, which is approximately 7.6 percent above the pressure at the same location in the model before any production took place (around July, 1980). The initial pressure at the same location in the reservoir was 1,677 psia (obtained by adjusting the initial 1,668 psia measured pressure for depth).

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Q85 ***Are You Confident That The Model Reasonably Predicts The Actual Pressures The Reservoir Will Exert On The Cap Rock During SNGS' Operation of The Gas Storage Reservoir?***

Yes, because the values were generated by our history matched model of the reservoir.

Q86 ***Can Pressure At The Cap Rock Be Accurately Monitored During Operation Of The Field Using Currently Available Technology?***

Yes, observation wells are customarily drilled for that purpose.

Q87 ***Can Bottom Hole Reservoir Pressure Be Accurately Monitored During Operation Of The Field Using Currently Available Technology?***

Yes.

Q88 ***Can Wellhead Pressure Be Easily Controlled Using Currently Available Technology?***

Yes.

Q89 ***Does Dr. Robertson's Testimony Reflect An Accurate Understanding Of The Reservoir's Pressures?***

No. Dr. Robertson states on page seven of his testimony that "[t]he suggested maximum pressure for the project that they suggest is 1750 psi (SNGS 1161) which is greater than the initial pressure (SNGS 1424) of the reservoir." 1750 psi was the maximum flowing bottom hole pressure used in the injector wellbores for a portion of Ryder Scott's interim work (the final operating conditions are described previously in Q62). In any case, it was *not* the maximum pressure suggested for the entire reservoir. A constraint of 1750 psi maximum flowing bottom hole pressure in the wells will maintain the average reservoir pressure *below* the initial average reservoir pressure 1668 psi. The fact that this number was clearly identified in Ryder Scott's work as a flowing bottom hole pressure and not a pressure in the reservoir is a further indication of Dr. Robertson's carelessness in reviewing Ryder Scott's work.

Q90 ***Is Dr. Robertson Correct When He States That "The Well Logs Show That The Remainder Of The Reservoir [Below The Top 10 Feet] Is Water-Wet And Remains At Virgin Pressures."***

No. We challenge Dr. Robertson to provide evidence from the well logs showing that any part of the reservoir still remains at virgin pressure. It is physically impossible to obtain pressures from the well logs available for this field.

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Q91 ***Is Dr. Robertson Correct When He States That The "Computer Runs Show Much Higher Pressures Than Virgin (Initial Reservoir) Pressure, But These Pressures Are Unrealistic As Fracturing Of The Cap Rock Will Occur (At Fracturing Pressure) And Gas Will Immediately Begin To Migrate To The Surface."***

No. As detailed in Exhibit F, there are no pressures in the reservoir directly adjacent to the cap rock which exceed initial reservoir pressure by more than 10% in computer runs. Although there are no measured fracture pressures for the cap rock, it is generally accepted that staying within 10% of the initial pressure is well below the anticipated fracture pressure. For a more detailed discussion of this subject, Ryder Scott respectfully directs the ALJ to "Evaluation of Cap Rock Integrity And Risk of Gas Release" prepared for SNGS by Golder Associates, dated June 2008, which we understand was submitted to the California Public Utilities Commission's Energy Division as part of the environmental review process for this Project.

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F. SUMMARY

Q92 ***Please Summarize Your Response To Dr. Robertson's Testimony***

The nature, number, and importance of Dr. Robertson's calculation and conceptual errors strongly suggest that he is unqualified to render the opinions he offers. Further, the results presented in his testimony are unreliable for presentation in a public forum for consideration by a regulatory authority.

EXHIBIT A

BIOGRAPHICAL DATA

BRUCE A PALMER, Senior Simulation Engineer

EDUCATION

MS degree, chemical engineering, Brigham Young University, 2000
BS degree, chemical engineering, Brigham Young University, 1993

PROFESSIONAL ASSOCIATIONS

Member, Society of Petroleum Engineers
American Institute of Chemical Engineers
Member, Tau Beta Pi Engineering Honor Society
Member, Phi Kappa Phi Honor Society

AREA OF EXPERTISE

Reservoir Simulation: Conducted numerous reservoir simulation studies of oil and gas fields worldwide. Experience with all phases of simulation studies including initial design, model construction, history matching, calibration, and final documentation. Examples include construction of primary recovery models for field evaluation and development, and gas field and gas storage models for deliverability estimation.

Reservoir Engineering: Experience in application of traditional engineering techniques such as decline curve analysis, volumetric analysis, PVT and rock properties analysis, nodal analysis, and material balance analysis.

Reserves and Economic Evaluations: Experience in reserves estimation in accordance with SEC and SPE reserves estimation guidelines.

SUMMARY OF EMPLOYMENT

Ryder Scott Co. LP 2006 to Present
Responsible for reservoir engineering and modeling studies including integrated geoscience/ engineering studies throughout the world. Examples for recent studies are pre-production development study for a multi-zone deepwater Gulf of Mexico field, gas deliverability studies for several prospective gas storage fields and reserves estimation for several gas condensate fields in Japan.

ExxonMobil Production Co. 2004 to 2006
Senior Engineer
Member of a team of engineers responsible for simulation studies and development planning for Qatar North Field. Presented technical work to partner companies RasGas and QatarGas. Interacted with various engineering and geoscience professionals and

management. Improved the run time and general usability of several existing simulation models.

ExxonMobil Exploration and Production Malaysia Inc 2002 to 2004
Senior Project Engineer
Technical point of contact for simulation support in the Asia Pacific region. Implemented new reservoir simulation network and trained a total of 50 engineers in Kuala Lumpur, Jakarta, and Melbourne. Worked together with engineers building models for the following fields: Tapis, Irong Barat, Tabu, Tuna, Flounder, Turrum, Kipper, East Pilchard, Northern Sumatra Offshore, and Cepu. Worked with geologic modelers on scale-up of Petrel models for simulation.

ExxonMobil Exploration Co. 2000 to 2002
Project Engineer
Member of a support team for simulation engineers world wide. Aided engineers from all ExxonMobil Production Company affiliates, ExxonMobil Development Company, and Upstream Research Center Reservoir Division. Implemented new reservoir simulation network and trained engineers in London. Interacted extensively with simulation software developers.

ExxonMobil Production Co. 1998 to 2000
Project Engineer
Lead engineer for East Texas oil field and Gladewater, Delrose, and Overton gas fields. Evaluated, designed, recommended and secured management approval for in-fill drillwells and workover programs for gas fields. Ensured compliance with complicated Texas Railroad Commission East Texas Field Rules. Updated company planning basis.

EG&G Rocky Flats 1993 to 1995
Environmental Engineer
Coordinated plant-wide process waste sampling and analysis program. Supervised first sampling of containerized low-level radioactive waste.

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GEOGRAPHICAL AREAS OF EXPERIENCE

Domestic United States
- California
- Gulf of Mexico
- Louisiana
- Pennsylvania
- Texas
- West Virginia

International
- Australia
- Indonesia
- Japan
- Malaysia
- Qatar
- Venezuela

EXHIBIT B

Table 4

California Natural Gas Storage, LLC
Florin Gas Storage Field Winters Formation Simulation Study

Unocal Florin #2 Bottom Hole Pressures
(3,895 ft MD, 3,493 ft ss)

Survey Date	Reservoir Pressure (psia)
11/30/80	1,668
01/18/81	1,651
06/07/81	1,671
08/07/81	1,638
11/29/81	1,641
03/01/82	1,636
05/28/82	1,636
09/03/82	1,644
10/08/82	1,647
11/24/82	1,687
12/28/82	1,654
04/27/83	1,660
05/02/83	1,649
07/01/83	1,625
07/05/83	1,622
11/23/83	1,594
12/27/83	1,558
06/21/85	1,382
11/19/86	1,115

EXHIBIT C

Table 1

California Natural Gas Storage, LLC
Florin Gas Storage Field Winters Formation Simulation Study

Pertinent Model Parameters

Model Dimensions, I x J x K	137 x 180 x 16
Number of Active Grid Cells	265,104
Model Porosity (percent)	31.0
Model Horizontal Permeability (md)	30.0
Model Vertical Permeability (md)	10.0
Rock Compressibility (1×10^{-6}/psi)	6.0
Initial Reservoir Pressure (psia) @ 3,493 ft ss	1,668
Reservoir Temperature (F)	97
Initial Gas-Water Contact (ft-ss)	3,795
Initial Water Saturation S_{wc} (percent)	33.0
Gas Effective Relative Permeability End Point K_{rg} (fraction)	0.8
Water Effective Relative Permeability End Point K_{rw} (fraction)	0.6
Trapped Gas Saturation S_{gc} (percent)	22.0
Gas Gravity (Where air = 1)	0.598
Model OGIP (Bscf)	13.8

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EXHIBIT D

Table 6

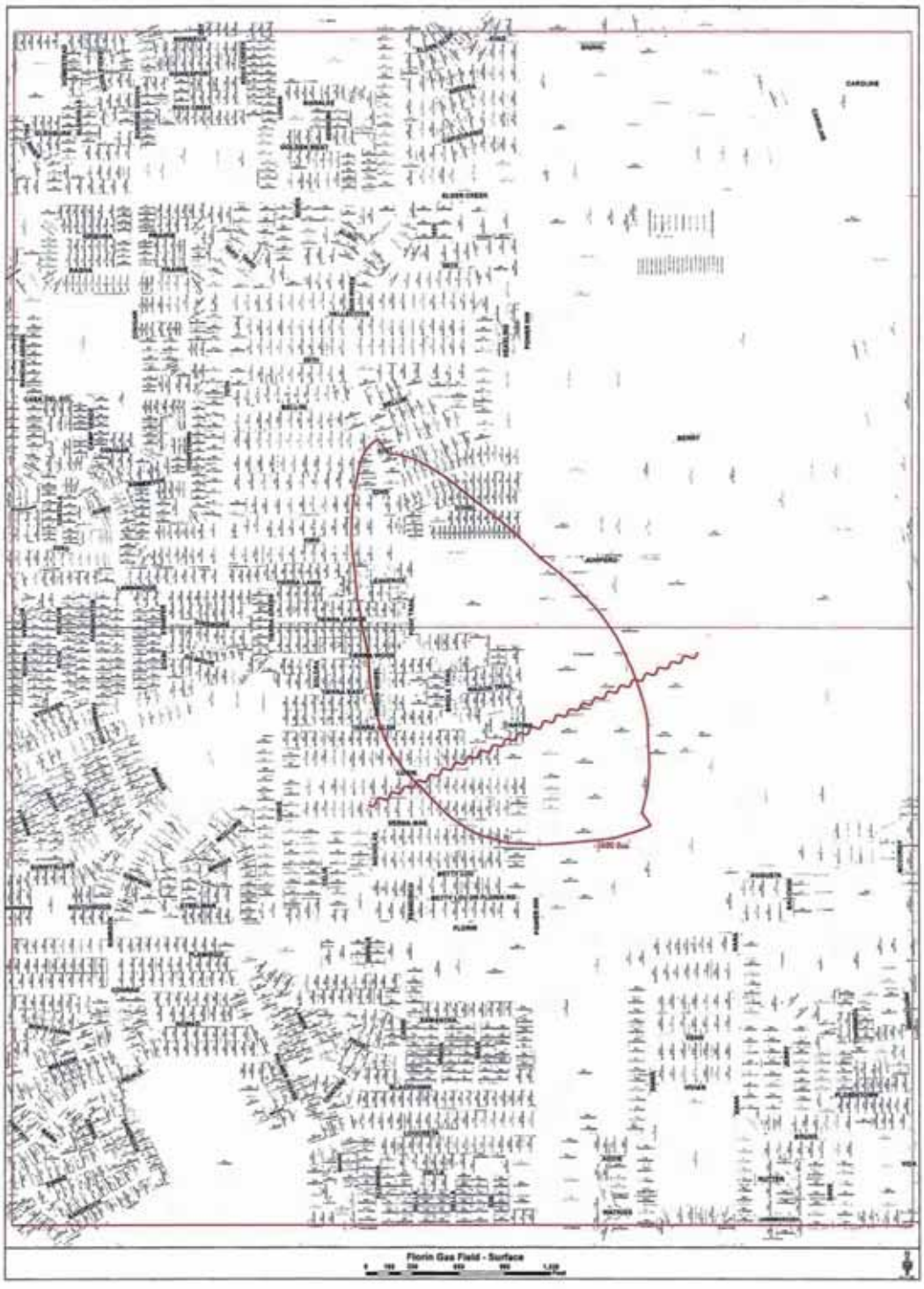
California Natural Gas Storage, LLC
Florin Gas Storage Field Winters Formation Simulation Study

Simulation Model Aquifer Parameters

Thickness (ft)	250	350
Porosity (percent)	31.0	31.0
Permeability (md)	80.0	80.0
Radius (ft)	2500	2500
Angle (Fraction of Circle)	0.74	0.74
Modeling Method	Carter-Tracy (Limited Extent)	Carter-Tracy (Limited Extent)
R-Ratio	2.5	2.5

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EXHIBIT E



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EXHIBIT F

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5218 TELEPHONE 713-651-9191
FAX 713-651-0849

June 30, 2008

Mr. Jim Fossum
Sacramento Natural Gas Storage, LLC
8031 Fruitridge Road, Suite B
Sacramento, CA 95820

Dear Mr. Fossum:

The purpose of this letter is to provide you with the pressure results of the latest prediction scenario of injection and production cycles for the Florin gas storage project which was run using Ryder Scott's numerical simulation model. For completeness, **Figure 1** provides an illustration of the geological model which the current dynamic numerical simulation model is based on. As mapped, the volume of the structure shown was too large to match historical production rates and pressures with the dynamic model. Therefore reservoir rock was assumed to be of poorer quality (low permeability and porosity) in the area of the structure with the highest uncertainty. **Figure 1** shows this area of low quality (i.e., non-productive) rock toward the south-east. This area is interpreted to not affect the reservoir performance either during primary production or storage operations. Since the area was not expected to impact reservoir performance, it was deactivated in the dynamic models to conserve computation time. All subsequent model runs and displays of model results show this area to be inactive (the model's history match supports the view that this area does not contribute to or effect reservoir performance). The details of the prediction scenario are as follows:

1. Six injectors/producers of approximately 1,000 ft in length were placed in the model parallel to each other and running roughly from east to west. An areal view of the well completions in the simulation grid is shown in **Figure 2**.
2. Gas injection commenced in the prediction scenario starting in July, 2009. Gas injection was subject to the following constraints:
    a. The maximum allowed well head pressure for each well was 1,650 psia.
    b. The maximum field-wide injection rate allowed was 100 MMscf/d.
3. Injection of gas occurred under these constraints until the incremental amount of gas injected reached 7.5 Bscf; at this point injection ceased and production began.
4. Gas production was subject to the following constraints:
    a. The minimum allowed well head pressure for each well was 650 psia.
    b. The maximum field-wide production rate allowed was 200 MMscf/d.
5. Production of gas occurred under these constraints until the incremental amount of gas produced reached 7.5 Bscf; at this point production ceased and injection began.
6. This injection and production cycle was repeated three times.

Figure 3 shows the seven grid cell locations picked for comparison of pressures throughout the injection and production cycles. **Table 1** shows the X, Y, and depth coordinates of these seven grid cells in the simulation model coordinate system. **Table 2** contains the grid cell pressure values for dates during the production and injection cycles.

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1200, 530 - 8TH AVENUE, S.W. CALGARY, ALBERTA T2P 3S8 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303)623-4258

Flowing bottom hole pressure for the injectors and producers was also reported for comparison **Table 3** shows the X, Y and depth coordinates of the flowing bottom hole pressures in the simulation model coordinate system, which corresponds to the heel of each horizontal well. **Tables 4 through 9** contains the flowing bottom hole pressure values for each injector/producer well for selected dates during the production and injection cycles.

Figure 4 is a graph of pressure versus time for the grid cell 66,74,1 which experienced the highest pressures during injection. As shown in **Table 2**, the maximum pressure reached during injection in this cell is 1804.6 psia, which is 7.6% above the initial pressure of 1677.02 psia on July of 1980 prior to production. The initial reservoir pressure in this grid cell and 10% above this original pressure are labeled for reference. **Figure 5** is a bar chart comparing the pressure at each of the seven grid cell locations for initial conditions and at the end of the first, second, and third injection cycle when pressure is at a maximum. **Figure 6** shows the deviation of the final injection pressure from the initial pressure as a percentage for each of the locations. These figures show that in the numerical simulation, the forecasted pressures exerted on the cap rock never exceed 10% above the original (pre-production) reservoir pressure. Moreover, observation of the graph shows that forecasted pressures never exceed 8% above the original.

Thank you for the opportunity to perform this work. We look forward to continue working with you in the future. Please let us know if you have any questions or comments.

Very truly yours,

RYDER SCOTT COMPANY, L.P.

Bruce Palmer
Petroleum Engineer

Dean C. Rietz, P.E.
Managing Senior Vice President

/pl

STATE OF TEXAS
DEAN C. RIETZ
70507
PROFESSIONAL LICENSE

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(Cont.)

Sacramento Natural Gas Storage

Florin Field

Geological Model

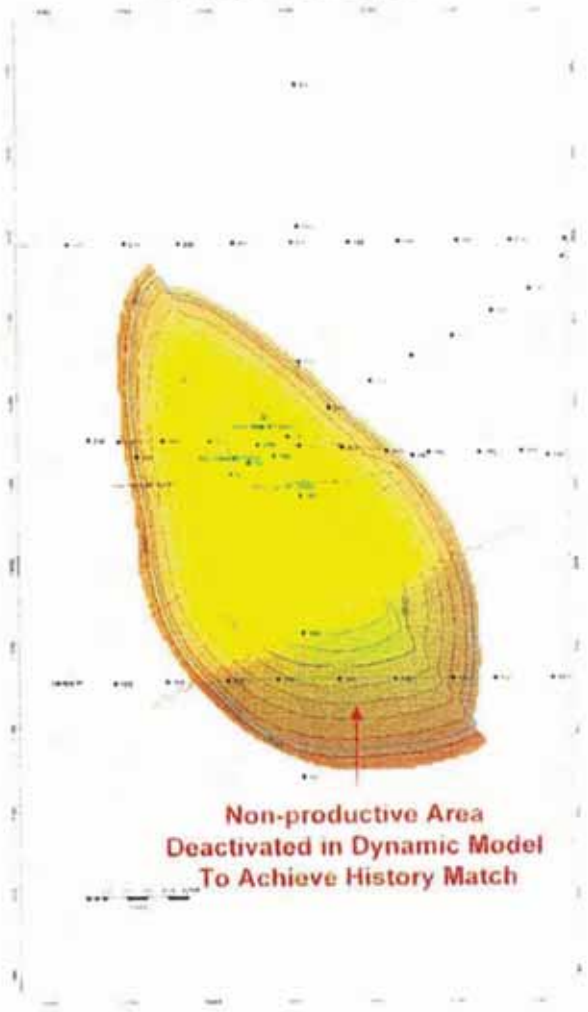
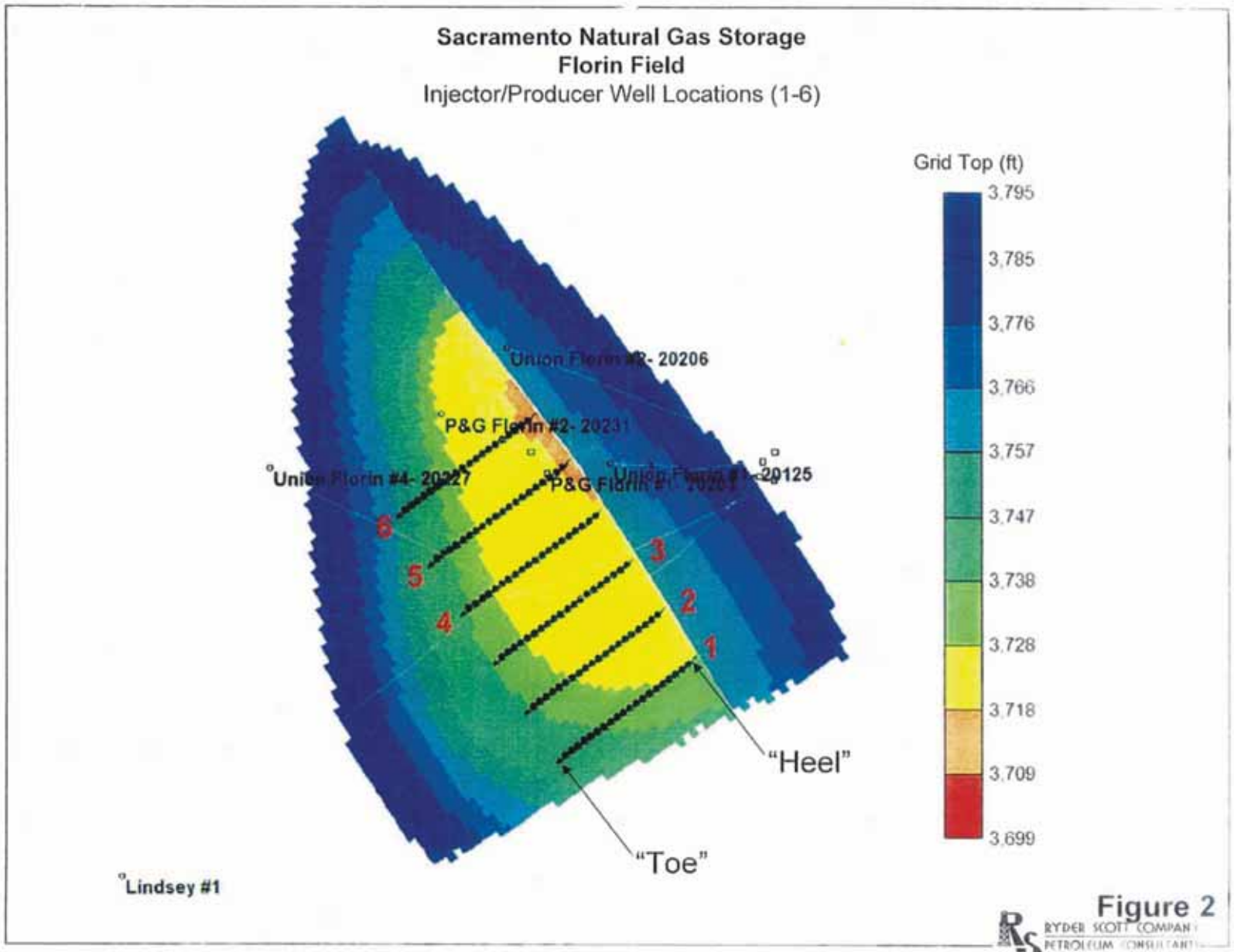


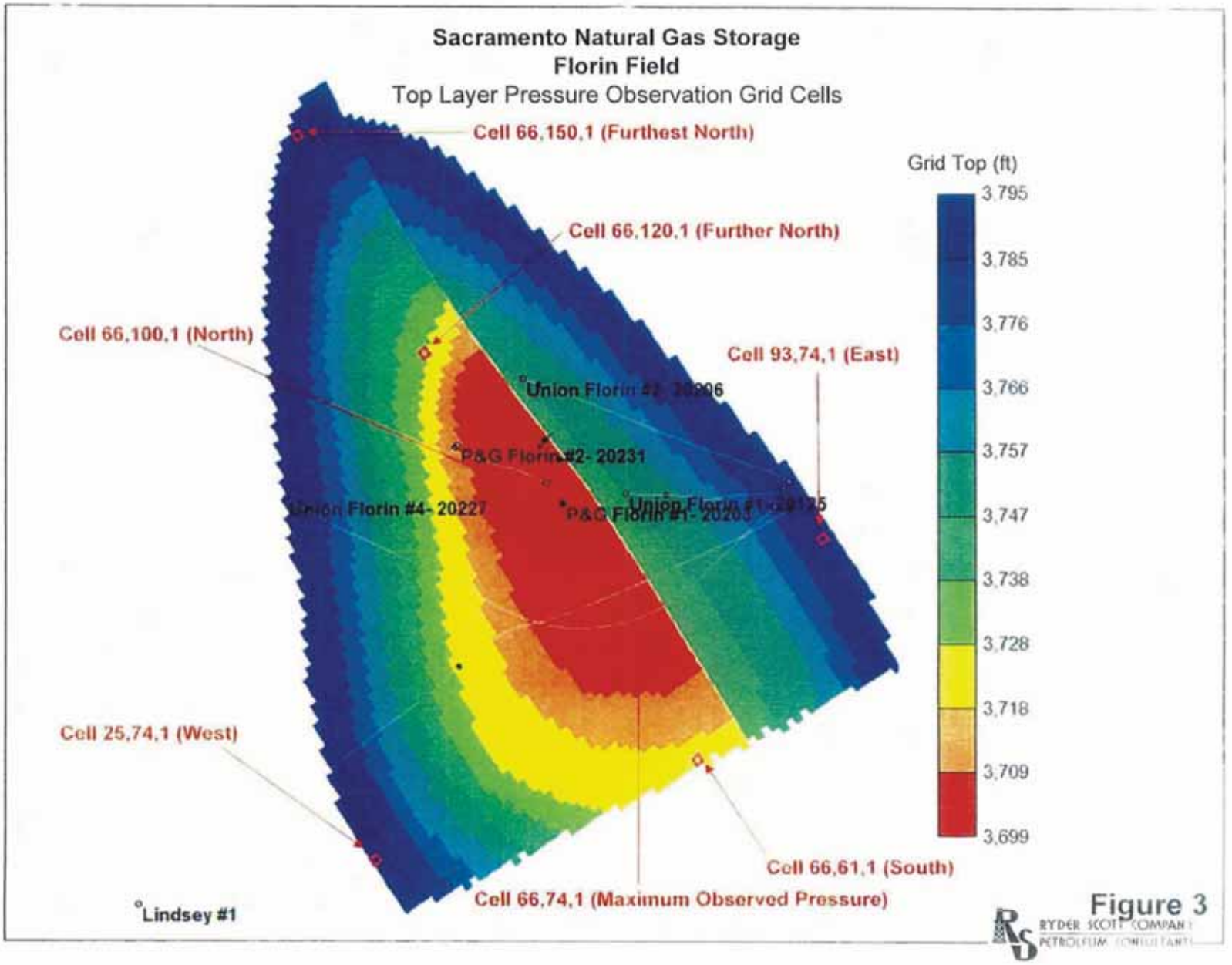
Figure 1

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

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(Cont.)


Sacramento Natural Gas Storage
Florin Field
Injector/Producer Well Locations (1-6)
Grid Top (ft)
3,795
3,785
3,776
3,766
3,757
3,747
3,738
3,728
3,718
3,709
3,699
Union Florin #2- 20206
P&G Florin #2- 20231
Union Florin #4- 20227
P&G Florin #1- 20233
Union Florin #1- 20125
Lindsey #1
1
2
3
4
5
6
"Heel"
"Toe"
Figure 2
RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

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(Cont.)


Sacramento Natural Gas Storage
Florin Field
Top Layer Pressure Observation Grid Cells
Cell 66,150,1 (Furthest North)
Cell 66,120,1 (Further North)
Cell 66,100,1 (North)
Cell 93,74,1 (East)
Union Florin #2- 20206
P&G Florin #2- 20231
Union Florin #4- 20227
P&G Florin #1- 20203
Cell 25,74,1 (West)
Cell 66,61,1 (South)
Cell 66,74,1 (Maximum Observed Pressure)
Lindsey #1
Grid Top (ft)
3,795
3,785
3,776
3,766
3,757
3,747
3,738
3,728
3,718
3,709
3,699
Figure 3
RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

D2-292
(Cont.)

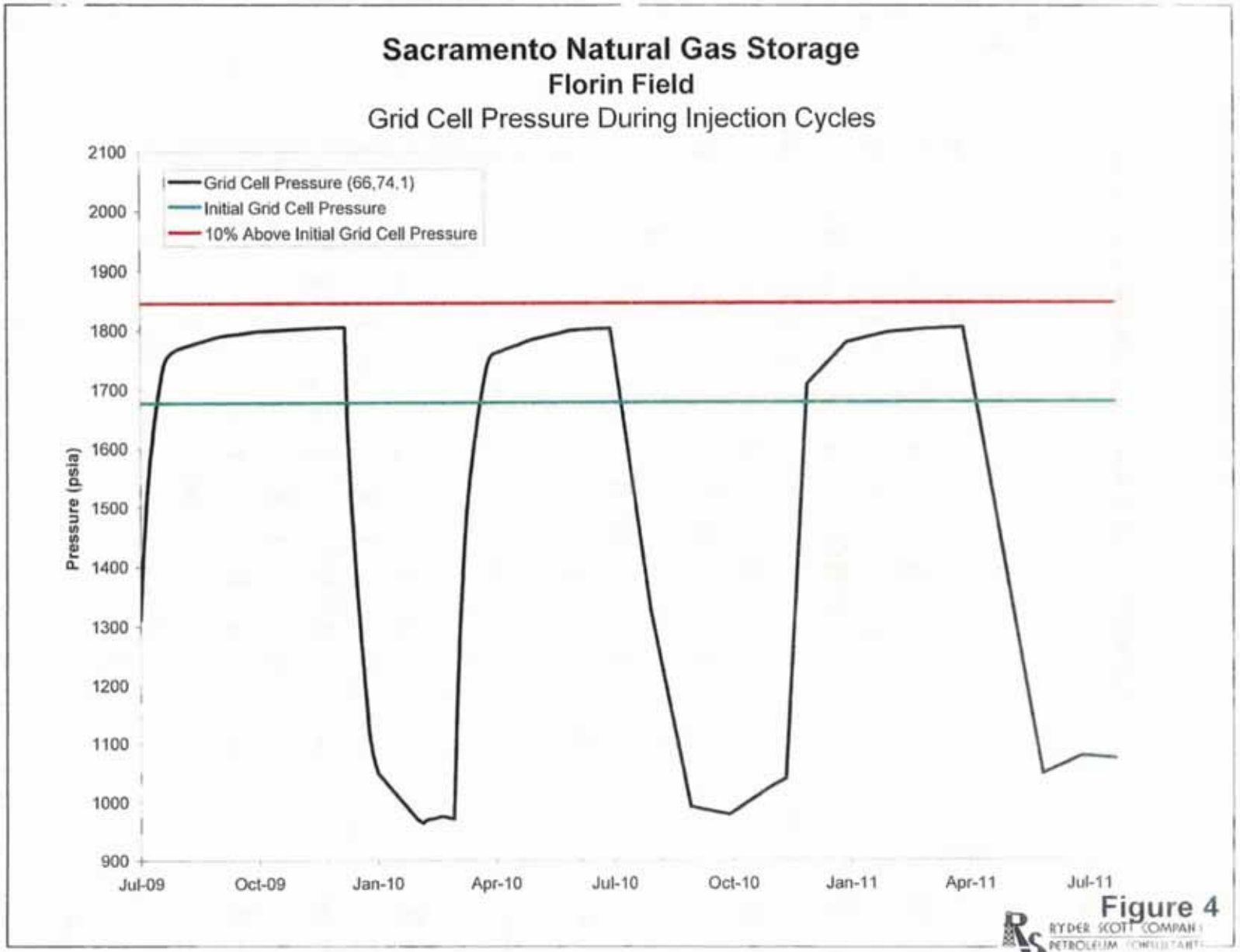
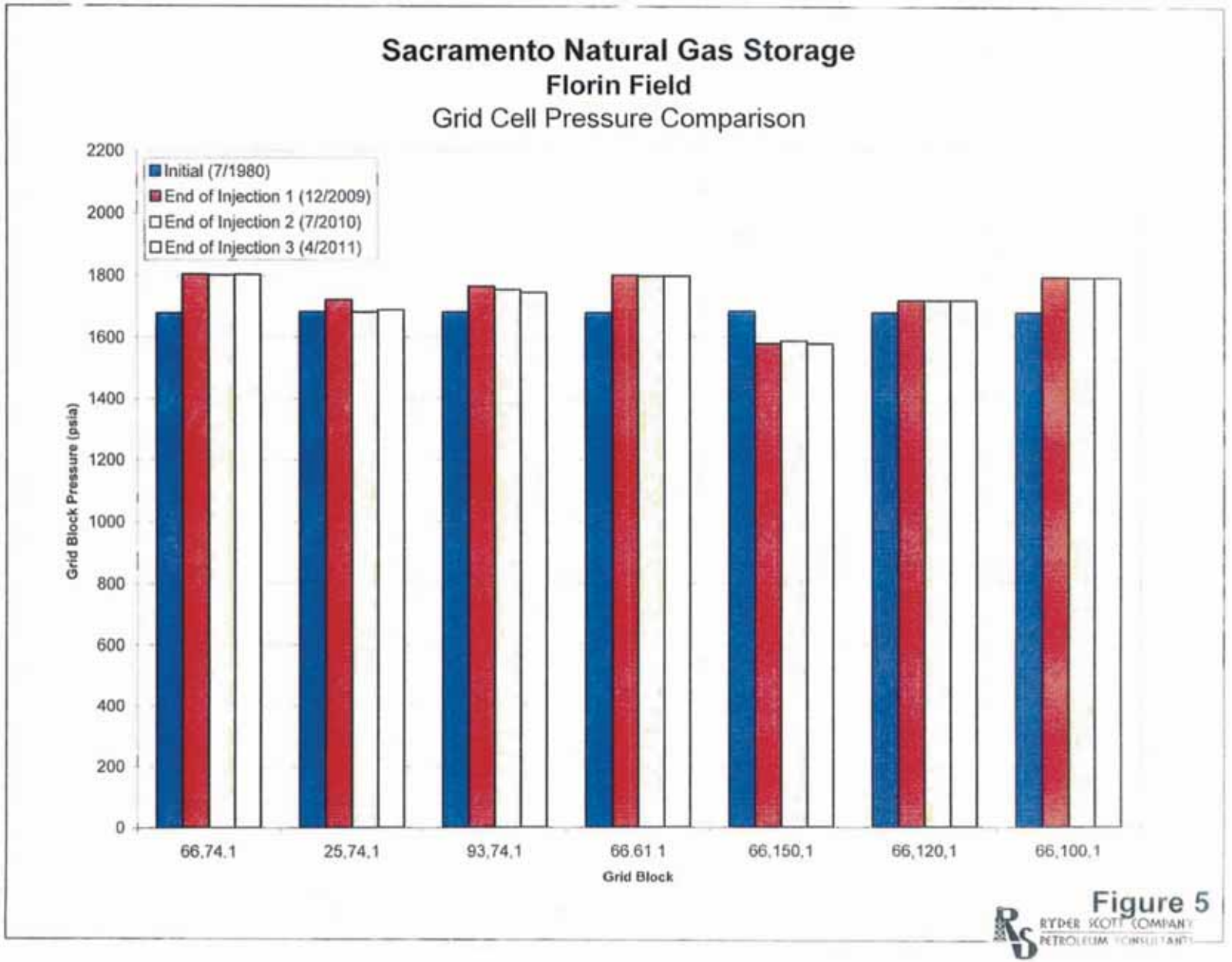


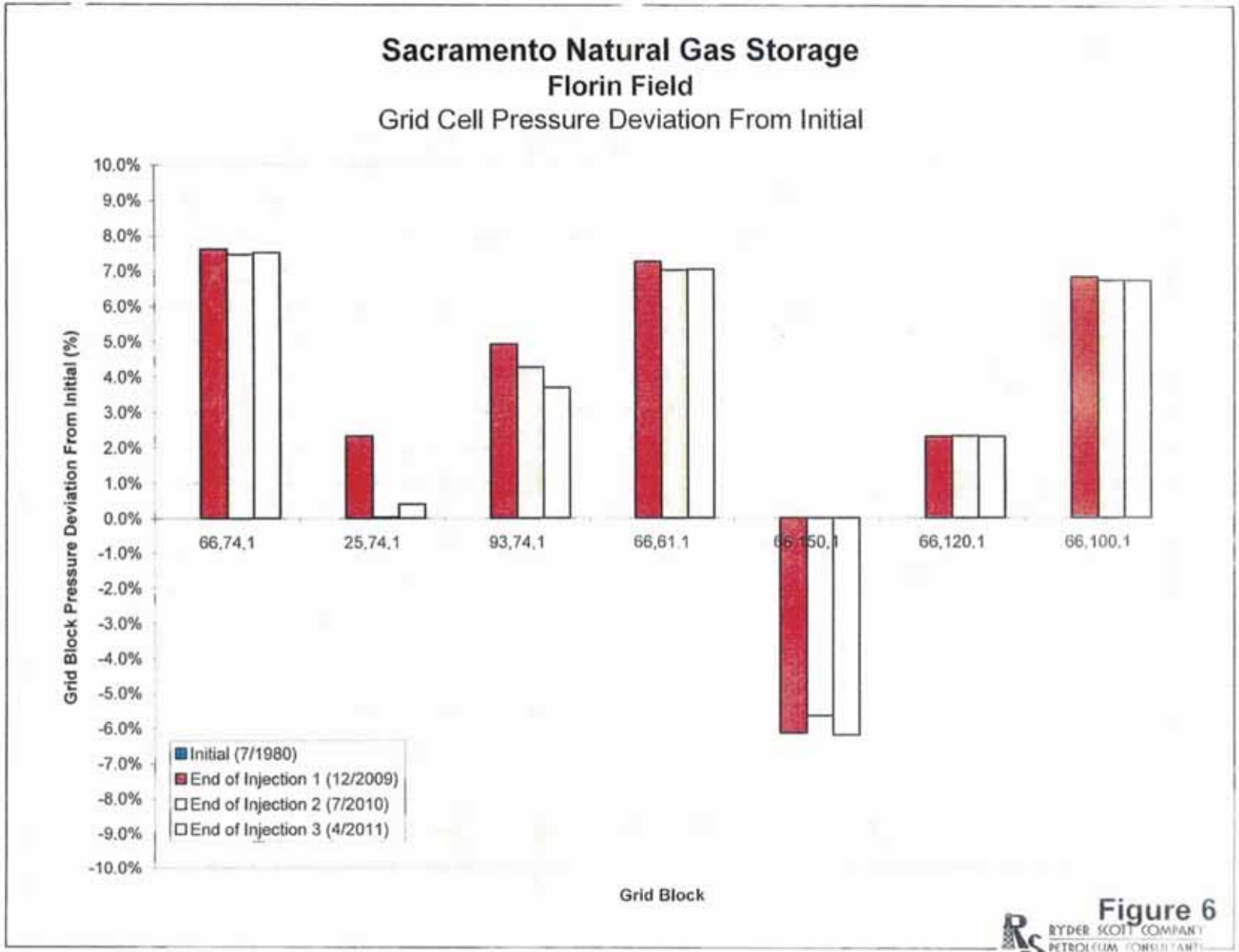
Figure 4

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

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(Cont.)


Sacramento Natural Gas Storage
Florin Field
Grid Cell Pressure Comparison
Initial (7/1980)
End of Injection 1 (12/2009)
End of Injection 2 (7/2010)
End of Injection 3 (4/2011)
Grid Block Pressure (psia)
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
66,74,1
25,74,1
93,74,1
66,61 1
66,150,1
66,120,1
66,100,1
Grid Block
Figure 5
RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

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(Cont.)


Sacramento Natural Gas Storage
Florin Field
Grid Cell Pressure Deviation From Initial
Grid Block Pressure Deviation From Initial (%)
10.0%
9.0%
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
-6.0%
-7.0%
-8.0%
-9.0%
-10.0%
66,74,1
25,74,1
93,74,1
66,61,1
66,120,1
66,100,1
Initial (7/1980)
End of Injection 1 (12/2009)
End of Injection 2 (7/2010)
End of Injection 3 (4/2011)
Grid Block
Figure 6
RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

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(Cont.)

Table 1

Sacramento Natural Gas Storage
Florin Gas Storage Field

Simulation Model Grid Cell Coordinates and Depths (Cell Center)

Grid Cell	Coordinates (ft) X	Coordinates (ft) Y	Depth (ft) Z
66 150 1	17,238	17,216	3,797
66 120 1	18,038	15,944	3,733
66 100 1	18,646	15,146	3,709
93 74 1	20,555	14,847	3,793
25 74 1	17,725	12,953	3,796
66 74 1	19,402	14,084	3,712
66 61 1	19,767	13,543	3,726

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(Cont.)

Table 2

Sacramento Natural Gas Storage
Florin Gas Storage Field

Grid Cell Pressure Values Through Time

	Pressure (psi) at Specific Grid Cells						
Date	66 74 1	25 74 1	93 74 1	66 61 1	66 150 1	66 120 1	66 100 1
07/01/1980	1,677.02	1,660.93	1,680.37	1,677.61	1,681.46	1,677.88	1,676.91
07/01/2009	1,311.98	1,333.26	1,328.08	1,312.52	1,332.29	1,312.42	1,311.72
07/02/2009	1,369.02	1,333.26	1,328.08	1,340.81	1,332.28	1,313.60	1,360.85
07/03/2009	1,414.69	1,333.26	1,328.11	1,378.12	1,332.28	1,317.42	1,399.02
07/04/2009	1,452.87	1,333.27	1,328.23	1,413.37	1,332.27	1,323.48	1,430.54
07/05/2009	1,486.11	1,333.31	1,328.51	1,445.19	1,332.26	1,331.37	1,458.30
07/06/2009	1,515.60	1,333.38	1,329.08	1,473.94	1,332.26	1,340.65	1,483.55
07/07/2009	1,542.03	1,333.50	1,330.06	1,499.93	1,332.26	1,350.95	1,507.47
07/08/2009	1,566.08	1,333.69	1,331.57	1,523.68	1,332.27	1,362.02	1,529.97
07/09/2009	1,588.14	1,333.97	1,333.74	1,545.62	1,332.29	1,373.65	1,551.26
07/10/2009	1,608.52	1,334.34	1,336.66	1,566.01	1,332.33	1,385.66	1,571.43
07/11/2009	1,627.39	1,334.81	1,340.44	1,585.04	1,332.38	1,397.92	1,590.57
07/12/2009	1,644.90	1,335.40	1,345.14	1,602.82	1,332.44	1,410.34	1,608.75
07/13/2009	1,661.21	1,336.12	1,350.77	1,619.48	1,332.54	1,422.88	1,626.04
07/14/2009	1,676.45	1,336.98	1,357.34	1,635.14	1,332.66	1,435.48	1,642.48
07/15/2009	1,690.71	1,337.98	1,364.86	1,649.87	1,332.81	1,448.02	1,658.12
07/16/2009	1,704.11	1,339.14	1,373.31	1,663.78	1,333.00	1,460.52	1,672.99
07/17/2009	1,716.71	1,340.46	1,382.60	1,676.93	1,333.23	1,472.91	1,687.16
07/18/2009	1,728.68	1,341.96	1,392.59	1,689.44	1,333.51	1,485.18	1,700.67
07/19/2009	1,738.99	1,343.65	1,403.26	1,700.78	1,333.83	1,497.25	1,712.65
07/20/2009	1,745.71	1,345.54	1,414.46	1,709.69	1,334.22	1,508.97	1,720.99
07/21/2009	1,750.52	1,347.63	1,426.21	1,716.63	1,334.67	1,520.22	1,727.32
07/22/2009	1,754.19	1,349.93	1,438.49	1,722.16	1,335.18	1,530.88	1,732.39
07/23/2009	1,757.10	1,352.46	1,451.06	1,726.67	1,335.76	1,540.87	1,736.58
07/24/2009	1,759.50	1,355.21	1,463.58	1,730.43	1,336.41	1,550.17	1,740.12

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(Cont.)

Table 2

Sacramento Natural Gas Storage
Florin Gas Storage Field

Grid Cell Pressure Values Through Time

	Pressure (psi) at Specific Grid Cells						
Date	66 74 1	25 74 1	93 74 1	66 61 1	66 150 1	66 120 1	66 100 1
07/25/2009	1,761.49	1,358.19	1,475.90	1,733.63	1,337.15	1,558.82	1,743.16
07/26/2009	1,763.19	1,361.41	1,487.93	1,736.40	1,337.96	1,566.63	1,745.79
07/27/2009	1,764.65	1,364.86	1,499.81	1,738.81	1,338.85	1,574.24	1,748.10
07/28/2009	1,765.94	1,368.54	1,511.78	1,740.96	1,339.83	1,581.10	1,750.14
07/29/2009	1,767.10	1,372.45	1,523.55	1,742.88	1,340.90	1,587.44	1,751.95
07/30/2009	1,768.15	1,376.58	1,534.73	1,744.63	1,342.05	1,593.31	1,753.60
07/31/2009	1,769.10	1,380.93	1,545.09	1,746.21	1,343.28	1,598.74	1,755.09
08/01/2009	1,769.98	1,385.48	1,554.67	1,747.67	1,344.59	1,603.77	1,756.44
09/01/2009	1,789.77	1,537.65	1,692.49	1,774.50	1,406.09	1,668.55	1,777.48
10/01/2009	1,797.68	1,622.73	1,732.43	1,788.79	1,465.30	1,687.76	1,783.64
11/01/2009	1,801.85	1,678.13	1,749.95	1,795.26	1,519.18	1,701.60	1,787.58
12/01/2009	1,804.43	1,713.86	1,761.09	1,799.07	1,571.31	1,714.19	1,791.07
12/02/2009	1,804.62	1,714.89	1,761.43	1,799.35	1,572.76	1,714.58	1,791.21
12/03/2009	1,804.52	1,715.94	1,761.78	1,799.30	1,573.83	1,714.95	1,791.26
12/04/2009	1,804.48	1,717.00	1,762.11	1,799.21	1,574.81	1,715.32	1,791.32
12/05/2009	1,804.53	1,718.04	1,762.43	1,799.24	1,575.80	1,715.68	1,791.40
12/06/2009	1,804.59	1,719.06	1,762.74	1,799.28	1,576.85	1,716.04	1,791.48
12/07/2009	1,804.64	1,720.05	1,763.03	1,799.35	1,577.93	1,716.40	1,791.58
12/08/2009	1,700.17	1,721.00	1,763.08	1,749.04	1,579.03	1,715.14	1,702.36
12/09/2009	1,632.93	1,721.64	1,762.01	1,695.58	1,580.16	1,710.46	1,644.67
12/10/2009	1,581.06	1,721.71	1,759.43	1,649.94	1,581.26	1,703.22	1,599.64
12/11/2009	1,537.11	1,720.98	1,756.09	1,609.32	1,582.33	1,694.03	1,560.79
12/12/2009	1,498.35	1,719.20	1,749.01	1,572.83	1,583.32	1,683.47	1,525.67
12/13/2009	1,462.71	1,716.36	1,741.28	1,539.08	1,584.18	1,671.86	1,493.02
12/14/2009	1,429.32	1,712.49	1,732.08	1,507.37	1,584.86	1,659.42	1,462.18

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(Cont.)

Table 2

Sacramento Natural Gas Storage
Florin Gas Storage Field

Grid Cell Pressure Values Through Time

	Pressure (psi) at Specific Grid Cells						
Date	66 74 1	26 74 1	93 74 1	66 61 1	66 150 1	66 120 1	66 100 1
12/15/2009	1,397.57	1,707.72	1,721.55	1,477.18	1,585.33	1,646.38	1,432.73
12/16/2009	1,366.98	1,702.09	1,709.71	1,448.19	1,585.56	1,632.90	1,404.38
12/17/2009	1,337.42	1,695.77	1,696.79	1,420.14	1,585.51	1,619.11	1,376.80
12/18/2009	1,308.72	1,688.77	1,683.05	1,392.87	1,585.16	1,605.08	1,350.04
12/19/2009	1,280.43	1,681.33	1,668.56	1,365.95	1,584.50	1,590.88	1,323.83
12/20/2009	1,253.57	1,673.38	1,653.56	1,339.88	1,583.51	1,576.55	1,297.24
12/21/2009	1,226.49	1,664.99	1,638.10	1,314.27	1,582.20	1,562.11	1,272.06
12/22/2009	1,200.26	1,656.25	1,622.32	1,289.20	1,580.59	1,547.60	1,246.43
12/23/2009	1,173.66	1,647.22	1,606.27	1,264.33	1,578.68	1,533.05	1,221.60
12/24/2009	1,147.48	1,637.99	1,590.03	1,239.62	1,576.48	1,518.43	1,196.03
12/25/2009	1,122.64	1,628.72	1,573.65	1,215.48	1,574.02	1,503.80	1,171.78
12/26/2009	1,105.43	1,619.41	1,557.13	1,195.07	1,571.30	1,489.29	1,154.17
12/27/2009	1,092.23	1,610.04	1,540.69	1,178.03	1,568.33	1,475.03	1,140.24
12/28/2009	1,081.24	1,600.73	1,524.32	1,163.27	1,565.14	1,461.15	1,128.44
12/29/2009	1,071.82	1,591.52	1,508.10	1,150.34	1,561.72	1,447.71	1,118.05
12/30/2009	1,063.45	1,582.50	1,492.02	1,138.74	1,558.15	1,434.72	1,108.74
12/31/2009	1,055.92	1,573.65	1,476.28	1,128.26	1,554.42	1,422.21	1,100.33
01/01/2010	1,048.99	1,565.08	1,460.77	1,118.56	1,550.58	1,410.15	1,092.64
02/01/2010	968.88	1,415.87	1,222.62	998.20	1,443.40	1,198.90	1,036.93
02/02/2010	967.88	1,412.64	1,219.91	996.43	1,441.62	1,196.75	1,036.61
02/03/2010	966.66	1,409.42	1,217.26	994.27	1,439.83	1,194.77	1,039.53
02/04/2010	964.84	1,406.26	1,214.56	991.26	1,438.11	1,192.88	1,039.87
02/05/2010	964.16	1,403.15	1,211.83	992.63	1,436.48	1,191.03	1,039.68
02/06/2010	965.69	1,400.12	1,209.15	996.81	1,434.96	1,189.20	1,039.21
02/07/2010	967.66	1,397.18	1,206.62	999.79	1,433.57	1,187.39	1,038.66

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(Cont.)

Table 2

Sacramento Natural Gas Storage
Florin Gas Storage Field

Grid Cell Pressure Values Through Time

	Pressure (psi) at Specific Grid Cells						
Date	66 74 1	25 74 1	93 74 1	66 61 1	66 150 1	66 120 1	66 100 1
02/08/2010	968.98	1,394.33	1,204.26	1,001.70	1,432.30	1,185.58	1,038.07
02/09/2010	969.82	1,391.57	1,202.10	1,002.94	1,431.13	1,183.76	1,037.44
02/10/2010	970.37	1,388.91	1,200.06	1,003.78	1,430.04	1,181.95	1,036.78
02/11/2010	970.73	1,386.34	1,198.09	1,004.36	1,429.04	1,180.14	1,036.11
02/12/2010	970.96	1,383.87	1,196.17	1,004.75	1,428.11	1,178.34	1,035.46
02/13/2010	971.11	1,381.50	1,194.30	1,004.96	1,427.23	1,176.55	1,034.81
02/14/2010	971.42	1,379.23	1,192.51	1,004.94	1,426.41	1,174.76	1,034.49
02/15/2010	972.11	1,377.06	1,190.84	1,004.82	1,425.63	1,173.02	1,034.66
02/16/2010	972.90	1,374.97	1,189.32	1,004.67	1,424.88	1,171.32	1,034.93
02/17/2010	973.60	1,372.98	1,187.96	1,004.22	1,424.16	1,169.67	1,035.14
02/18/2010	974.14	1,371.08	1,186.75	1,003.83	1,423.48	1,168.07	1,035.24
02/19/2010	974.50	1,369.26	1,185.66	1,003.40	1,422.83	1,166.51	1,035.23
02/20/2010	974.64	1,367.53	1,184.67	1,002.91	1,422.20	1,165.01	1,035.12
02/21/2010	974.54	1,365.87	1,183.76	1,002.28	1,421.59	1,163.54	1,034.90
02/22/2010	974.21	1,364.29	1,182.90	1,001.51	1,421.00	1,162.10	1,034.57
02/23/2010	973.73	1,362.78	1,182.10	1,000.67	1,420.42	1,160.68	1,034.14
02/24/2010	973.22	1,361.34	1,181.36	999.86	1,419.85	1,159.27	1,033.63
02/25/2010	972.72	1,359.97	1,180.69	999.13	1,419.28	1,157.88	1,033.11
02/26/2010	972.25	1,358.65	1,180.10	998.48	1,418.72	1,156.51	1,032.59
02/27/2010	971.81	1,357.40	1,179.58	997.89	1,418.17	1,155.15	1,032.05
02/28/2010	971.39	1,356.21	1,179.14	997.34	1,417.62	1,153.79	1,031.48
03/01/2010	970.96	1,355.07	1,178.78	996.80	1,417.08	1,152.43	1,030.89
03/02/2010	1,053.52	1,353.96	1,178.47	1,028.36	1,416.56	1,151.86	1,089.38
03/03/2010	1,124.23	1,352.90	1,178.22	1,076.52	1,416.04	1,153.55	1,139.83
03/04/2010	1,186.84	1,351.90	1,178.04	1,127.46	1,415.54	1,157.44	1,183.11

D2-292
(Cont.)

Table 2

Sacramento Natural Gas Storage
Florin Gas Storage Field

Grid Cell Pressure Values Through Time

Date	Pressure (psi) at Specific Grid Cells						
	66 74 1	25 74 1	93 74 1	66 61 1	66 150 1	66 120 1	66 100 1
03/05/2010	1,242.19	1,350.95	1,177.98	1,177.61	1,415.06	1,163.37	1,221.36
03/06/2010	1,291.25	1,350.05	1,178.07	1,224.70	1,414.58	1,171.07	1,256.89
03/07/2010	1,335.54	1,349.20	1,178.36	1,268.18	1,414.13	1,180.27	1,287.86
03/08/2010	1,376.02	1,348.39	1,178.94	1,308.78	1,413.70	1,190.68	1,317.80
03/09/2010	1,413.27	1,347.65	1,179.87	1,346.75	1,413.29	1,202.04	1,346.03
03/10/2010	1,447.23	1,346.96	1,181.25	1,382.14	1,412.92	1,213.96	1,372.65
03/11/2010	1,477.76	1,346.36	1,183.18	1,414.66	1,412.58	1,226.42	1,397.71
03/12/2010	1,504.89	1,345.84	1,185.76	1,444.03	1,412.29	1,239.39	1,421.26
03/13/2010	1,527.72	1,345.42	1,189.08	1,469.91	1,412.03	1,252.78	1,445.14
03/14/2010	1,548.00	1,345.11	1,193.20	1,492.28	1,411.83	1,266.56	1,468.75
03/15/2010	1,566.51	1,344.94	1,198.19	1,512.09	1,411.68	1,280.69	1,491.72
03/16/2010	1,584.08	1,344.91	1,204.06	1,530.35	1,411.59	1,295.12	1,513.16
03/17/2010	1,601.05	1,345.05	1,210.81	1,547.72	1,411.55	1,309.75	1,533.12
03/18/2010	1,617.31	1,345.36	1,218.43	1,564.43	1,411.57	1,324.49	1,552.17
03/19/2010	1,632.89	1,345.85	1,227.03	1,580.55	1,411.66	1,339.26	1,570.39
03/20/2010	1,647.76	1,346.54	1,236.65	1,596.11	1,411.80	1,354.01	1,587.89
03/21/2010	1,661.93	1,347.44	1,247.31	1,611.08	1,412.02	1,368.68	1,604.70
03/22/2010	1,675.41	1,348.54	1,258.98	1,625.45	1,412.30	1,383.25	1,620.85
03/23/2010	1,688.24	1,349.85	1,271.57	1,639.23	1,412.66	1 397.69	1,636.37
03/24/2010	1,700.49	1,351.38	1,284.94	1,652.44	1,413.08	1,411.98	1,651.32
03/25/2010	1,712.20	1,353.12	1,298.99	1,665.09	1,413.58	1,426.09	1,665.72
03/26/2010	1,723.37	1,355.09	1,313.79	1,677.21	1,414.15	1,440.02	1,679.60
03/27/2010	1,734.03	1,357.28	1,329.48	1,686.83	1,414.80	1,453.75	1,692.98
03/28/2010	1,743.24	1,359.69	1,345.81	1,699.46	1,415.53	1,467.25	1,704.91
03/29/2010	1,749.24	1,362.33	1,362.39	1,707.89	1,416.34	1,480.38	1,713.34

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(Cont.)

Table 2

Sacramento Natural Gas Storage
Florin Gas Storage Field

Grid Cell Pressure Values Through Time

	Pressure (psi) at Specific Grid Cells						
Date	66 74 1	25 74 1	93 74 1	66 61 1	66 150 1	66 120 1	66 100 1
03/30/2010	1,753.51	1,365.19	1,378.91	1,714.52	1,417.23	1,493.04	1,719.85
03/31/2010	1,756.76	1,368.29	1,395.18	1,719.86	1,418.21	1,505.12	1,725.17
04/01/2010	1,759.36	1,371.61	1,411.10	1,724.29	1,419.27	1,516.58	1,729.67
05/01/2010	1,782.86	1,518.38	1,663.42	1,755.75	1,476.33	1,666.57	1,772.03
06/01/2010	1,798.86	1,624.35	1,729.72	1,789.60	1,535.27	1,702.54	1,785.78
06/16/2010	1,801.12	1,657.25	1,744.09	1,793.55	1,561.73	1,710.81	1,788.19
07/01/2010	1,802.15	1,681.44	1,752.11	1,795.27	1,586.18	1,716.74	1,789.76
08/01/2010	1,328.74	1,680.26	1,700.47	1,418.02	1,612.68	1,632.71	1,388.20
09/01/2010	990.84	1,451.75	1,307.96	1,041.53	1,507.70	1,285.03	1,027.35
10/01/2010	977.77	1,368.39	1,228.32	1,027.36	1,444.95	1,163.34	1,003.79
11/01/2010	1,023.32	1,336.93	1,215.15	1,035.28	1,428.14	1,102.74	998.61
11/14/2010	1,038.94	1,332.78	1,220.30	1,045.16	1,422.35	1,098.08	1,041.96
12/01/2010	1,708.14	1,331.86	1,248.68	1,656.14	1,416.05	1,341.48	1,630.16
01/01/2011	1,778.88	1,424.40	1,543.89	1,755.41	1,437.49	1,630.69	1,763.74
02/01/2011	1,795.15	1,565.19	1,677.35	1,781.67	1,488.81	1,687.95	1,781.44
03/01/2011	1,800.77	1,637.44	1,721.94	1,791.44	1,532.18	1,704.84	1,786.67
03/04/2011	1,801.20	1,645.17	1,725.61	1,792.31	1,537.95	1,706.47	1,787.16
04/01/2011	1,803.06	1,687.60	1,742.45	1,795.51	1,576.88	1,716.43	1,789.82
06/01/2011	1,047.09	1,439.51	1,347.22	1,140.43	1,507.83	1,279.25	1,043.26
07/01/2011	1,077.05	1,380.20	1,279.34	1,136.63	1,456.19	1,189.82	1,061.01
07/27/2011	1,072.61	1,353.45	1,277.10	1,120.95	1,441.37	1,173.10	1,127.70

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(Cont.)

Table 3

Sacramento Natural Gas Storage
Florin Gas Storage Field

X, Y, and Depth Coordinates Corresponding to the Flowing Bottom Hole Pressures

Well	Grid Block	X	Y	Depth (ft)
1	71 67 3	19,808.4	13,935.1	3,729.0
2	71 74 3	19,613.5	14,226.8	3,725.0
3	71 81 3	19,417.4	14,517.6	3,723.5
4	71 88 3	19,217.8	14,806.0	3,720.5
5	71 95 3	19,013.7	15,091.2	3,719.0
6	71 102 3	18,795.3	15,365.6	3,718.5

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(Cont.)

Table 4

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 1 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
07/03/2009	1,525.58	1,461.61
07/04/2009	1,559.35	1,494.34
07/05/2009	1,589.15	1,523.63
07/06/2009	1,616.16	1,550.34
07/07/2009	1,639.81	1,574.23
07/08/2009	1,661.70	1,596.37
07/09/2009	1,681.90	1,616.91
07/10/2009	1,700.66	1,636.08
07/11/2009	1,718.12	1,654.01
07/12/2009	1,734.42	1,670.82
07/13/2009	1,749.68	1,686.61
07/14/2009	1,764.01	1,701.48
07/15/2009	1,777.51	1,715.52
07/16/2009	1,790.26	1,728.81
07/17/2009	1,802.32	1,741.41
07/18/2009	1,813.85	1,753.45
07/19/2009	1,821.90	1,763.01
07/20/2009	1,821.90	1,766.98
07/21/2009	1,821.90	1,770.14
07/22/2009	1,821.90	1,772.76
07/23/2009	1,821.90	1,774.96
07/24/2009	1,821.90	1,776.85
07/25/2009	1,821.90	1,778.50
07/26/2009	1,821.90	1,779.95
07/27/2009	1,821.90	1,781.23
07/28/2009	1,821.90	1,782.38
07/29/2009	1,821.90	1,783.43
07/30/2009	1,821.90	1,784.38
07/31/2009	1,821.90	1,785.25
08/01/2009	1,821.90	1,786.05
09/01/2009	1,821.90	1,800.47
10/01/2009	1,821.90	1,806.97
11/01/2009	1,821.90	1,809.83
12/01/2009	1,821.90	1,811.47
12/02/2009	1,821.90	1,811.61
12/03/2009	1,821.90	1,811.51
12/04/2009	1,821.90	1,811.49
12/05/2009	1,821.90	1,811.51

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(Cont.)

Table 4

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 1 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
12/06/2009	1,821.90	1,811.55
12/07/2009	1,821.90	1,811.57
12/08/2009	1,505.98	1,614.61
12/09/2009	1,443.43	1,558.41
12/10/2009	1,392.33	1,511.96
12/11/2009	1,341.96	1,467.73
12/12/2009	1,302.03	1,430.45
12/13/2009	1,263.06	1,394.77
12/14/2009	1,226.63	1,361.23
12/15/2009	1,191.47	1,328.99
12/16/2009	1,157.46	1,297.86
12/17/2009	1,124.24	1,267.55
12/18/2009	1,091.75	1,237.98
12/19/2009	1,057.30	1,207.65
12/20/2009	1,026.55	1,179.55
12/21/2009	994.05	1,150.83
12/22/2009	963.29	1,123.23
12/23/2009	930.80	1,094.88
12/24/2009	899.09	1,067.01
12/25/2009	872.27	1,041.52
12/26/2009	873.77	1,032.21
12/27/2009	875.22	1,024.50
12/28/2009	876.60	1,017.94
12/29/2009	877.81	1,012.06
12/30/2009	879.00	1,006.78
12/31/2009	880.20	1,002.06
01/01/2010	881.37	997.65
02/01/2010	911.09	952.10
02/02/2010	912.24	951.92
02/03/2010	913.64	951.79
02/04/2010	915.63	951.72
02/05/2010	995.46	995.46
02/06/2010	1,000.26	1,000.26
02/07/2010	1,001.70	1,001.70
02/08/2010	1,002.30	1,002.30
02/09/2010	1,002.76	1,002.76
02/10/2010	1,003.20	1,003.20
02/11/2010	1,003.56	1,003.56

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(Cont.)

Table 4

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 1 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
02/12/2010	1,003.86	1,003.86
02/13/2010	1,004.09	1,004.09
02/14/2010	1,004.24	1,004.24
02/15/2010	1,004.40	1,004.40
02/16/2010	1,004.53	1,004.53
02/17/2010	1,004.59	1,004.59
02/18/2010	1,004.59	1,004.59
02/19/2010	1,004.51	1,004.51
02/20/2010	1,004.33	1,004.33
02/21/2010	1,003.99	1,003.99
02/22/2010	1,003.45	1,003.45
02/23/2010	1,002.77	1,002.77
02/24/2010	1,002.05	1,002.05
02/25/2010	1,001.37	1,001.37
02/26/2010	1,000.75	1,000.75
02/27/2010	1,000.15	1,000.15
02/28/2010	999.58	999.58
03/01/2010	999.02	999.02
03/02/2010	1,208.23	1,135.48
03/03/2010	1,260.34	1,187.27
03/04/2010	1,308.91	1,236.05
03/05/2010	1,354.59	1,282.14
03/06/2010	1,396.72	1,324.52
03/07/2010	1,436.00	1,363.70
03/08/2010	1,472.93	1,400.44
03/09/2010	1,507.70	1,435.01
03/10/2010	1,540.10	1,467.31
03/11/2010	1,569.65	1,496.95
03/12/2010	1,595.97	1,523.63
03/13/2010	1,617.88	1,546.52
03/14/2010	1,635.20	1,565.60
03/15/2010	1,651.78	1,583.42
03/16/2010	1,668.20	1,600.66
03/17/2010	1,684.56	1,617.55
03/18/2010	1,700.13	1,633.71
03/19/2010	1,715.14	1,649.31
03/20/2010	1,729.54	1,664.31
03/21/2010	1,743.31	1,678.70

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(Cont.)

Table 4

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 1 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
03/22/2010	1,756.47	1,692.48
03/23/2010	1,769.05	1,705.67
03/24/2010	1,781.12	1,718.33
03/25/2010	1,792.69	1,730.48
03/26/2010	1,803.79	1,742.15
03/27/2010	1,814.46	1,753.35
03/28/2010	1,821.90	1,762.27
03/29/2010	1,821.90	1,766.03
03/30/2010	1,821.90	1,769.03
03/31/2010	1,821.90	1,771.55
04/01/2010	1,821.90	1,773.70
05/01/2010	1,821.90	1,795.67
06/01/2010	1,821.90	1,807.40
06/16/2010	1,821.90	1,809.06
07/01/2010	1,821.90	1,809.75
08/01/2010	1,264.81	1,264.81
09/01/2010	921.94	977.72
10/01/2010	1,024.07	1,024.07
11/01/2010	1,035.49	1,035.49
11/14/2010	1,045.68	1,045.68
12/01/2010	1,785.32	1,721.56
01/01/2011	1,821.90	1,789.36
02/01/2011	1,821.90	1,803.39
03/01/2011	1,821.90	1,807.96
03/04/2011	1,821.90	1,808.34
04/01/2011	1,821.90	1,809.71
06/01/2011	1,130.60	1,130.60
07/01/2011	1,125.90	1,125.90
07/27/2011	1,112.95	1,112.95

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(Cont.)

Table 5

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 2 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
07/03/2009	1,525.31	1,465.60
07/04/2009	1,560.07	1,500.18
07/05/2009	1,590.53	1,530.81
07/06/2009	1,617.37	1,558.15
07/07/2009	1,641.41	1,582.82
07/08/2009	1,663.52	1,605.50
07/09/2009	1,683.88	1,626.43
07/10/2009	1,702.73	1,645.84
07/11/2009	1,720.20	1,663.90
07/12/2009	1,736.40	1,680.70
07/13/2009	1,751.50	1,696.40
07/14/2009	1,765.64	1,711.12
07/15/2009	1,778.88	1,724.94
07/16/2009	1,791.32	1,737.95
07/17/2009	1,803.06	1,750.23
07/18/2009	1,814.23	1,761.93
07/19/2009	1,821.90	1,771.09
07/20/2009	1,821.90	1,774.75
07/21/2009	1,821.90	1,777.55
07/22/2009	1,821.90	1,779.81
07/23/2009	1,821.90	1,781.68
07/24/2009	1,821.90	1,783.25
07/25/2009	1,821.90	1,784.61
07/26/2009	1,821.90	1,785.78
07/27/2009	1,821.90	1,786.80
07/28/2009	1,821.90	1,787.72
07/29/2009	1,821.90	1,788.55
07/30/2009	1,821.90	1,789.31
07/31/2009	1,821.90	1,790.00
08/01/2009	1,821.90	1,790.64
09/01/2009	1,821.90	1,803.91
10/01/2009	1,821.90	1,808.60
11/01/2009	1,821.90	1,810.88
12/01/2009	1,821.90	1,812.26
12/02/2009	1,821.90	1,812.38
12/03/2009	1,821.90	1,812.27
12/04/2009	1,821.90	1,812.27
12/05/2009	1,821.90	1,812.29

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(Cont.)

Table 5

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 2 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
12/06/2009	1,821.90	1,812.34
12/07/2009	1,821.90	1,812.34
12/08/2009	1,503.32	1,609.08
12/09/2009	1,437.29	1,547.53
12/10/2009	1,384.22	1,497.86
12/11/2009	1,337.49	1,454.24
12/12/2009	1,296.48	1,415.50
12/13/2009	1,257.79	1,379.25
12/14/2009	1,221.25	1,345.09
12/15/2009	1,186.13	1,312.37
12/16/2009	1,152.07	1,280.76
12/17/2009	1,118.81	1,250.01
12/18/2009	1,086.23	1,220.02
12/19/2009	1,052.76	1,189.87
12/20/2009	1,024.14	1,162.63
12/21/2009	990.90	1,133.26
12/22/2009	961.53	1,106.05
12/23/2009	928.83	1,077.29
12/24/2009	898.74	1,049.84
12/25/2009	872.91	1,024.58
12/26/2009	874.37	1,015.61
12/27/2009	875.97	1,008.53
12/28/2009	877.32	1,002.36
12/29/2009	878.50	997.02
12/30/2009	879.76	992.33
12/31/2009	880.95	988.12
01/01/2010	882.11	984.20
02/01/2010	911.56	946.46
02/02/2010	912.67	946.38
02/03/2010	914.02	946.32
02/04/2010	915.97	946.29
02/05/2010	917.49	946.20
02/06/2010	917.33	946.21
02/07/2010	916.73	946.33
02/08/2010	916.51	946.56
02/09/2010	916.57	946.87
02/10/2010	916.72	947.18
02/11/2010	916.87	947.43

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(Cont.)

Table 5

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 2 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
02/12/2010	917.02	947.64
02/13/2010	917.19	947.82
02/14/2010	917.23	948.01
02/15/2010	917.01	948.23
02/16/2010	916.73	948.48
02/17/2010	916.49	948.72
02/18/2010	916.39	948.96
02/19/2010	916.44	949.20
02/20/2010	916.68	949.46
02/21/2010	917.12	949.72
02/22/2010	917.70	949.95
02/23/2010	918.29	950.09
02/24/2010	918.79	950.13
02/25/2010	919.20	950.10
02/26/2010	919.56	950.02
02/27/2010	919.89	949.93
02/28/2010	920.19	949.84
03/01/2010	920.51	949.75
03/02/2010	1,200.18	1,130.64
03/03/2010	1,261.09	1,192.76
03/04/2010	1,315.46	1,248.65
03/05/2010	1,364.35	1,298.93
03/06/2010	1,408.34	1,343.50
03/07/2010	1,448.78	1,384.13
03/08/2010	1,485.33	1,421.71
03/09/2010	1,521.28	1,456.66
03/10/2010	1,553.30	1,488.78
03/11/2010	1,581.90	1,517.76
03/12/2010	1,607.13	1,543.64
03/13/2010	1,625.13	1,563.96
03/14/2010	1,642.66	1,582.92
03/15/2010	1,658.85	1,600.38
03/16/2010	1,675.09	1,617.39
03/17/2010	1,691.19	1,634.02
03/18/2010	1,706.43	1,649.86
03/19/2010	1,721.03	1,665.06
03/20/2010	1,734.92	1,679.57
03/21/2010	1,748.11	1,693.40

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(Cont.)

Table 5

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 2 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
03/22/2010	1,760.66	1,706.57
03/23/2010	1,772.60	1,719.13
03/24/2010	1,784.01	1,731.16
03/25/2010	1,794.88	1,742.65
03/26/2010	1,805.26	1,753.63
03/27/2010	1,815.18	1,764.12
03/28/2010	1,821.90	1,772.32
03/29/2010	1,821.90	1,775.65
03/30/2010	1,821.90	1,778.21
03/31/2010	1,821.90	1,780.27
04/01/2010	1,821.90	1,781.99
05/01/2010	1,821.90	1,799.16
06/01/2010	1,821.90	1,809.13
06/16/2010	1,821.90	1,810.41
07/01/2010	1,821.90	1,810.92
08/01/2010	1,243.13	1,243.13
09/01/2010	897.74	953.27
10/01/2010	913.22	949.27
11/01/2010	1,024.79	1,024.79
11/14/2010	1,040.33	1,040.33
12/01/2010	1,789.32	1,737.74
01/01/2011	1,821.90	1,795.16
02/01/2011	1,821.90	1,806.51
03/01/2011	1,821.90	1,810.00
03/04/2011	1,821.90	1,810.25
04/01/2011	1,821.90	1,811.19
06/01/2011	997.39	997.39
07/01/2011	979.28	1,029.88
07/27/2011	971.27	1,023.63

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(Cont.)

Table 6

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 3 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
07/03/2009	1,523.45	1,464.89
07/04/2009	1,558.55	1,500.17
07/05/2009	1,589.52	1,531.57
07/06/2009	1,617.10	1,559.76
07/07/2009	1,641.39	1,584.92
07/08/2009	1,663.76	1,608.03
07/09/2009	1,684.31	1,629.27
07/10/2009	1,703.30	1,648.93
07/11/2009	1,720.87	1,667.16
07/12/2009	1,737.13	1,684.08
07/13/2009	1,752.24	1,699.83
07/14/2009	1,766.34	1,714.57
07/15/2009	1,779.51	1,728.36
07/16/2009	1,791.84	1,741.31
07/17/2009	1,803.44	1,753.49
07/18/2009	1,814.44	1,765.05
07/19/2009	1,821.90	1,774.04
07/20/2009	1,821.90	1,777.64
07/21/2009	1,821.90	1,780.37
07/22/2009	1,821.90	1,782.53
07/23/2009	1,821.90	1,784.29
07/24/2009	1,821.90	1,785.75
07/25/2009	1,821.90	1,786.99
07/26/2009	1,821.90	1,788.05
07/27/2009	1,821.90	1,788.98
07/28/2009	1,821.90	1,789.80
07/29/2009	1,821.90	1,790.54
07/30/2009	1,821.90	1,791.22
07/31/2009	1,821.90	1,791.83
08/01/2009	1,821.90	1,792.40
09/01/2009	1,821.90	1,805.37
10/01/2009	1,821.90	1,808.90
11/01/2009	1,821.90	1,810.87
12/01/2009	1,821.90	1,812.15
12/02/2009	1,821.90	1,812.25
12/03/2009	1,821.90	1,812.17
12/04/2009	1,821.90	1,812.16
12/05/2009	1,821.90	1,812.19

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(Cont.)

Table 6

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 3 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
12/06/2009	1,821.90	1,812.24
12/07/2009	1,821.90	1,812.25
12/08/2009	1,503.61	1,608.83
12/09/2009	1,436.02	1,545.23
12/10/2009	1,381.26	1,493.52
12/11/2009	1,335.47	1,449.70
12/12/2009	1,293.73	1,410.04
12/13/2009	1,254.95	1,373.31
12/14/2009	1,218.21	1,338.70
12/15/2009	1,182.99	1,305.66
12/16/2009	1,148.80	1,273.74
12/17/2009	1,115.47	1,242.75
12/18/2009	1,082.75	1,212.52
12/19/2009	1,051.30	1,183.35
12/20/2009	1,021.78	1,155.60
12/21/2009	989.61	1,126.71
12/22/2009	959.90	1,099.25
12/23/2009	928.13	1,070.85
12/24/2009	898.42	1,043.53
12/25/2009	873.17	1,019.36
12/26/2009	874.93	1,009.80
12/27/2009	876.52	1,002.74
12/28/2009	877.86	996.72
12/29/2009	879.15	991.52
12/30/2009	880.41	986.99
12/31/2009	881.62	982.93
01/01/2010	882.79	979.25
02/01/2010	912.39	944.97
02/02/2010	913.47	944.88
02/03/2010	914.93	944.78
02/04/2010	916.98	944.59
02/05/2010	919.46	944.12
02/06/2010	973.60	973.60
02/07/2010	977.66	977.66
02/08/2010	979.45	979.45
02/09/2010	980.48	980.48
02/10/2010	981.12	981.12
02/11/2010	981.53	981.53

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(Cont.)

Table 6

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 3 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
02/12/2010	981.78	981.78
02/13/2010	981.92	981.92
02/14/2010	983.76	983.76
02/15/2010	987.05	987.05
02/16/2010	990.03	990.03
02/17/2010	992.43	992.43
02/18/2010	994.25	994.25
02/19/2010	995.56	995.56
02/20/2010	996.42	996.42
02/21/2010	996.84	996.84
02/22/2010	996.89	996.89
02/23/2010	996.62	996.62
02/24/2010	996.14	996.14
02/25/2010	995.56	995.56
02/26/2010	994.89	994.89
02/27/2010	994.19	994.19
02/28/2010	993.48	993.48
03/01/2010	992.73	992.73
03/02/2010	1,202.24	1,133.40
03/03/2010	1,262.92	1,196.16
03/04/2010	1,318.93	1,254.50
03/05/2010	1,369.08	1,306.44
03/06/2010	1,413.87	1,352.04
03/07/2010	1,454.69	1,393.22
03/08/2010	1,492.24	1,430.93
03/09/2010	1,526.81	1,465.62
03/10/2010	1,558.03	1,497.07
03/11/2010	1,585.60	1,525.17
03/12/2010	1,609.89	1,550.20
03/13/2010	1,626.76	1,569.63
03/14/2010	1,644.40	1,588.52
03/15/2010	1,660.58	1,605.91
03/16/2010	1,676.88	1,622.93
03/17/2010	1,693.02	1,639.57
03/18/2010	1,708.24	1,655.38
03/19/2010	1,722.79	1,670.51
03/20/2010	1,736.59	1,684.92
03/21/2010	1,749.65	1,698.62

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(Cont.)

Table 6

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 3 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
03/22/2010	1,762.04	1,711.64
03/23/2010	1,773.82	1,724.04
03/24/2010	1,785.03	1,735.87
03/25/2010	1,795.68	1,747.14
03/26/2010	1,805.82	1,757.89
03/27/2010	1,815.46	1,768.13
03/28/2010	1,821.90	1,776.05
03/29/2010	1,821.90	1,779.28
03/30/2010	1,821.90	1,781.71
03/31/2010	1,821.90	1,783.63
04/01/2010	1,821.90	1,785.22
05/01/2010	1,821.90	1,800.64
06/01/2010	1,821.90	1,809.56
06/16/2010	1,821.90	1,810.63
07/01/2010	1,821.90	1,811.07
08/01/2010	1,235.10	1,235.10
09/01/2010	898.85	949.34
10/01/2010	984.42	984.42
11/01/2010	1,021.96	1,021.96
11/14/2010	1,037.55	1,037.55
12/01/2010	1,791.04	1,743.41
01/01/2011	1,821.90	1,797.70
02/01/2011	1,821.90	1,807.78
03/01/2011	1,821.90	1,810.62
03/04/2011	1,821.90	1,810.76
04/01/2011	1,821.90	1,811.57
06/01/2011	973.83	973.83
07/01/2011	1,098.41	1,098.41
07/27/2011	1,100.09	1,100.09

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(Cont.)

Table 7

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 4 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
07/03/2009	1,523.54	1,464.84
07/04/2009	1,558.59	1,500.14
07/05/2009	1,589.44	1,531.48
07/06/2009	1,616.92	1,559.63
07/07/2009	1,641.17	1,584.80
07/08/2009	1,663.51	1,607.94
07/09/2009	1,684.07	1,629.23
07/10/2009	1,703.11	1,648.97
07/11/2009	1,720.75	1,667.31
07/12/2009	1,737.11	1,684.35
07/13/2009	1,752.32	1,700.25
07/14/2009	1,766.51	1,715.12
07/15/2009	1,779.76	1,729.05
07/16/2009	1,792.13	1,742.10
07/17/2009	1,803.72	1,754.35
07/18/2009	1,814.65	1,765.94
07/19/2009	1,821.90	1,774.85
07/20/2009	1,821.90	1,778.50
07/21/2009	1,821.90	1,781.25
07/22/2009	1,821.90	1,783.41
07/23/2009	1,821.90	1,785.16
07/24/2009	1,821.90	1,786.61
07/25/2009	1,821.90	1,787.83
07/26/2009	1,821.90	1,788.87
07/27/2009	1,821.90	1,789.77
07/28/2009	1,821.90	1,790.56
07/29/2009	1,821.90	1,791.28
07/30/2009	1,821.90	1,791.92
07/31/2009	1,821.90	1,792.51
08/01/2009	1,821.90	1,793.05
09/01/2009	1,821.90	1,805.39
10/01/2009	1,821.90	1,808.32
11/01/2009	1,821.90	1,810.10
12/01/2009	1,821.90	1,811.37
12/02/2009	1,821.90	1,811.47
12/03/2009	1,821.90	1,811.42
12/04/2009	1,821.90	1,811.42
12/05/2009	1,821.90	1,811.43

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(Cont.)

Table 7

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 4 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
12/06/2009	1,821.90	1,811.48
12/07/2009	1,821.90	1,811.49
12/08/2009	1,500.73	1,606.48
12/09/2009	1,431.76	1,541.70
12/10/2009	1,375.85	1,488.91
12/11/2009	1,332.59	1,446.26
12/12/2009	1,289.94	1,405.99
12/13/2009	1,251.34	1,369.24
12/14/2009	1,214.48	1,334.46
12/15/2009	1,179.25	1,301.34
12/16/2009	1,145.01	1,269.35
12/17/2009	1,111.63	1,238.31
12/18/2009	1,078.80	1,208.01
12/19/2009	1,049.53	1,180.02
12/20/2009	1,018.96	1,151.77
12/21/2009	988.00	1,123.50
12/22/2009	957.91	1,095.86
12/23/2009	927.21	1,068.02
12/24/2009	897.95	1,040.98
12/25/2009	873.65	1,017.32
12/26/2009	875.55	1,007.90
12/27/2009	877.12	1,000.88
12/28/2009	878.44	994.93
12/29/2009	879.80	989.90
12/30/2009	881.10	985.38
12/31/2009	882.33	981.42
01/01/2010	883.49	977.93
02/01/2010	911.91	946.08
02/02/2010	912.72	946.07
02/03/2010	914.02	946.07
02/04/2010	915.89	945.90
02/05/2010	918.15	945.34
02/06/2010	919.07	944.96
02/07/2010	919.14	944.84
02/08/2010	919.29	944.91
02/09/2010	919.53	945.05
02/10/2010	919.82	945.20
02/11/2010	920.09	945.35

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(Cont.)

Table 7

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 4 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
02/12/2010	920.35	945.48
02/13/2010	920.62	945.60
02/14/2010	979.19	979.19
02/15/2010	986.81	986.81
02/16/2010	991.33	991.33
02/17/2010	994.43	994.43
02/18/2010	996.59	996.59
02/19/2010	998.07	998.07
02/20/2010	999.03	999.03
02/21/2010	999.54	999.54
02/22/2010	999.67	999.67
02/23/2010	999.50	999.50
02/24/2010	999.12	999.12
02/25/2010	998.61	998.61
02/26/2010	998.03	998.03
02/27/2010	997.39	997.39
02/28/2010	996.72	996.72
03/01/2010	996.00	996.00
03/02/2010	1,207.51	1,138.30
03/03/2010	1,268.60	1,202.02
03/04/2010	1,324.01	1,260.14
03/05/2010	1,372.63	1,310.52
03/06/2010	1,415.62	1,354.22
03/07/2010	1,454.54	1,393.53
03/08/2010	1,490.19	1,429.41
03/09/2010	1,522.96	1,462.40
03/10/2010	1,552.56	1,492.34
03/11/2010	1,578.90	1,519.25
03/12/2010	1,602.44	1,543.52
03/13/2010	1,622.05	1,564.59
03/14/2010	1,639.76	1,583.74
03/15/2010	1,656.56	1,601.71
03/16/2010	1,673.37	1,619.26
03/17/2010	1,689.97	1,636.39
03/18/2010	1,705.63	1,652.64
03/19/2010	1,720.59	1,668.19
03/20/2010	1,734.79	1,683.00
03/21/2010	1,748.24	1,697.09

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(Cont.)

Table 7

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 4 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
03/22/2010	1,760.98	1,710.48
03/23/2010	1,773.07	1,723.21
03/24/2010	1,784.56	1,735.35
03/25/2010	1,795.46	1,746.91
03/26/2010	1,805.79	1,757.92
03/27/2010	1,815.58	1,768.37
03/28/2010	1,821.90	1,776.36
03/29/2010	1,821.90	1,779.68
03/30/2010	1,821.90	1,782.17
03/31/2010	1,821.90	1,784.14
04/01/2010	1,821.90	1,785.75
05/01/2010	1,821.90	1,801.05
06/01/2010	1,821.90	1,809.13
06/16/2010	1,821.90	1,810.09
07/01/2010	1,821.90	1,810.49
08/01/2010	1,232.46	1,232.46
09/01/2010	899.67	949.52
10/01/2010	917.92	945.41
11/01/2010	1,017.67	1,017.67
11/14/2010	1,036.41	1,036.41
12/01/2010	1,791.10	1,741.46
01/01/2011	1,821.90	1,798.53
02/01/2011	1,821.90	1,807.79
03/01/2011	1,821.90	1,810.21
03/04/2011	1,821.90	1,810.35
04/01/2011	1,821.90	1,811.17
06/01/2011	1,057.49	1,057.49
07/01/2011	1,099.57	1,099.57
07/27/2011	1,115.31	1,115.31

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(Cont.)

Table 8

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 5 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
07/03/2009	1,524.08	1,463.43
07/04/2009	1,557.42	1,496.85
07/05/2009	1,586.57	1,526.37
07/06/2009	1,613.65	1,553.57
07/07/2009	1,637.31	1,577.92
07/08/2009	1,659.43	1,600.61
07/09/2009	1,680.00	1,621.73
07/10/2009	1,699.21	1,641.49
07/11/2009	1,717.17	1,660.01
07/12/2009	1,733.97	1,677.39
07/13/2009	1,749.69	1,693.71
07/14/2009	1,764.42	1,709.07
07/15/2009	1,778.21	1,723.51
07/16/2009	1,791.11	1,737.09
07/17/2009	1,803.19	1,749.87
07/18/2009	1,814.53	1,761.94
07/19/2009	1,821.90	1,771.19
07/20/2009	1,821.90	1,775.09
07/21/2009	1,821.90	1,778.06
07/22/2009	1,821.90	1,780.43
07/23/2009	1,821.90	1,782.37
07/24/2009	1,821.90	1,783.99
07/25/2009	1,821.90	1,785.36
07/26/2009	1,821.90	1,786.55
07/27/2009	1,821.90	1,787.58
07/28/2009	1,821.90	1,788.49
07/29/2009	1,821.90	1,789.30
07/30/2009	1,821.90	1,790.04
07/31/2009	1,821.90	1,790.70
08/01/2009	1,821.90	1,791.31
09/01/2009	1,821.90	1,802.97
10/01/2009	1,821.90	1,805.85
11/01/2009	1,821.90	1,807.67
12/01/2009	1,821.90	1,809.12
12/02/2009	1,821.90	1,809.20
12/03/2009	1,821.90	1,809.18
12/04/2009	1,821.90	1,809.22
12/05/2009	1,821.90	1,809.23

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(Cont.)

Table 8

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 5 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
12/06/2009	1,821.90	1,809.28
12/07/2009	1,821.90	1,809.30
12/08/2009	1,495.17	1,602.90
12/09/2009	1,427.06	1,539.66
12/10/2009	1,372.54	1,488.72
12/11/2009	1,332.16	1,448.43
12/12/2009	1,289.37	1,408.81
12/13/2009	1,251.33	1,372.89
12/14/2009	1,214.72	1,338.75
12/15/2009	1,179.76	1,306.21
12/16/2009	1,145.74	1,274.74
12/17/2009	1,112.54	1,244.17
12/18/2009	1,079.90	1,214.31
12/19/2009	1,050.21	1,186.41
12/20/2009	1,019.53	1,158.25
12/21/2009	988.69	1,130.28
12/22/2009	958.21	1,102.63
12/23/2009	927.78	1,075.17
12/24/2009	897.64	1,047.88
12/25/2009	873.58	1,024.40
12/26/2009	875.44	1,014.96
12/27/2009	877.00	1,007.92
12/28/2009	878.30	1,001.93
12/29/2009	879.67	996.71
12/30/2009	880.91	992.24
12/31/2009	882.11	988.22
01/01/2010	883.25	984.64
02/01/2010	902.75	952.15
02/02/2010	902.61	952.37
02/03/2010	902.91	952.56
02/04/2010	903.66	952.70
02/05/2010	904.78	952.63
02/06/2010	905.73	952.44
02/07/2010	906.40	952.26
02/08/2010	906.97	952.08
02/09/2010	907.48	951.92
02/10/2010	907.94	951.79
02/11/2010	908.37	951.69

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(Cont.)

Table 8

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 5 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
02/12/2010	908.75	951.62
02/13/2010	909.13	951.57
02/14/2010	908.51	951.75
02/15/2010	907.32	952.12
02/16/2010	906.44	952.46
02/17/2010	905.87	952.73
02/18/2010	905.55	952.95
02/19/2010	905.42	953.15
02/20/2010	905.45	953.32
02/21/2010	905.62	953.48
02/22/2010	905.90	953.59
02/23/2010	906.25	953.66
02/24/2010	906.63	953.68
02/25/2010	907.00	953.67
02/26/2010	907.37	953.64
02/27/2010	907.75	953.60
02/28/2010	908.13	953.53
03/01/2010	908.51	953.47
03/02/2010	1,219.65	1,149.33
03/03/2010	1,276.77	1,208.22
03/04/2010	1,325.19	1,258.47
03/05/2010	1,367.07	1,301.56
03/06/2010	1,404.27	1,339.44
03/07/2010	1,438.24	1,373.93
03/08/2010	1,469.68	1,405.81
03/09/2010	1,498.96	1,435.50
03/10/2010	1,526.02	1,463.04
03/11/2010	1,550.91	1,488.46
03/12/2010	1,573.85	1,511.99
03/13/2010	1,601.30	1,537.73
03/14/2010	1,622.79	1,559.65
03/15/2010	1,640.76	1,579.01
03/16/2010	1,659.17	1,598.15
03/17/2010	1,677.05	1,616.57
03/18/2010	1,693.99	1,634.07
03/19/2010	1,710.20	1,650.83
03/20/2010	1,725.67	1,666.66
03/21/2010	1,740.42	1,682.18

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(Cont.)

Table 8

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 5 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
03/22/2010	1,754.44	1,696.79
03/23/2010	1,767.77	1,710.73
03/24/2010	1,780.48	1,724.06
03/25/2010	1,792.57	1,736.80
03/26/2010	1,804.05	1,748.96
03/27/2010	1,814.91	1,760.53
03/28/2010	1,821.90	1,769.40
03/29/2010	1,821.90	1,773.20
03/30/2010	1,821.90	1,776.12
03/31/2010	1,821.90	1,778.49
04/01/2010	1,821.90	1,780.47
05/01/2010	1,821.90	1,799.16
06/01/2010	1,821.90	1,806.67
06/16/2010	1,821.90	1,807.73
07/01/2010	1,821.90	1,808.30
08/01/2010	1,247.82	1,247.82
09/01/2010	898.46	956.76
10/01/2010	1,001.09	1,001.09
11/01/2010	1,009.93	1,009.93
11/14/2010	1,038.58	1,038.58
12/01/2010	1,763.93	1,722.40
01/01/2011	1,821.90	1,795.58
02/01/2011	1,821.90	1,804.90
03/01/2011	1,821.90	1,807.39
03/04/2011	1,821.90	1,807.59
04/01/2011	1,821.90	1,808.64
06/01/2011	980.36	980.36
07/01/2011	1,083.98	1,083.98
07/27/2011	1,123.24	1,123.24

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(Cont.)

Table 9

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 6 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
07/03/2009	1,522.35	1,456.79
07/04/2009	1,548.55	1,483.32
07/05/2009	1,572.13	1,507.42
07/06/2009	1,593.46	1,529.56
07/07/2009	1,617.38	1,552.73
07/08/2009	1,639.25	1,574.33
07/09/2009	1,660.35	1,595.09
07/10/2009	1,680.45	1,614.90
07/11/2009	1,699.61	1,633.83
07/12/2009	1,717.92	1,651.92
07/13/2009	1,735.37	1,669.21
07/14/2009	1,752.03	1,685.73
07/15/2009	1,767.95	1,701.52
07/16/2009	1,783.14	1,716.61
07/17/2009	1,797.66	1,731.04
07/18/2009	1,811.61	1,744.89
07/19/2009	1,821.90	1,756.18
07/20/2009	1,821.90	1,760.57
07/21/2009	1,821.90	1,764.09
07/22/2009	1,821.90	1,767.04
07/23/2009	1,821.90	1,769.54
07/24/2009	1,821.90	1,771.70
07/25/2009	1,821.90	1,773.59
07/26/2009	1,821.90	1,775.24
07/27/2009	1,821.90	1,776.70
07/28/2009	1,821.90	1,778.01
07/29/2009	1,821.90	1,779.18
07/30/2009	1,821.90	1,780.24
07/31/2009	1,821.90	1,781.21
08/01/2009	1,821.90	1,782.09
09/01/2009	1,821.90	1,794.96
10/01/2009	1,821.90	1,798.63
11/01/2009	1,821.90	1,800.99
12/01/2009	1,821.90	1,803.11
12/02/2009	1,821.90	1,803.19
12/03/2009	1,821.90	1,803.22
12/04/2009	1,821.90	1,803.28
12/05/2009	1,821.90	1,803.32

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(Cont.)

Table 9

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 6 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
12/06/2009	1,821.90	1,803.38
12/07/2009	1,821.90	1,803.43
12/08/2009	1,494.44	1,601.43
12/09/2009	1,439.31	1,551.30
12/10/2009	1,394.08	1,509.77
12/11/2009	1,348.77	1,469.99
12/12/2009	1,309.98	1,434.75
12/13/2009	1,272.80	1,401.27
12/14/2009	1,237.52	1,369.47
12/15/2009	1,203.47	1,338.87
12/16/2009	1,170.43	1,309.25
12/17/2009	1,138.13	1,280.39
12/18/2009	1,106.60	1,252.25
12/19/2009	1,073.40	1,223.57
12/20/2009	1,034.57	1,192.08
12/21/2009	1,006.61	1,166.34
12/22/2009	969.80	1,136.41
12/23/2009	939.86	1,110.03
12/24/2009	900.88	1,079.27
12/25/2009	870.13	1,052.88
12/26/2009	871.72	1,043.63
12/27/2009	872.92	1,036.27
12/28/2009	873.95	1,029.79
12/29/2009	875.05	1,023.99
12/30/2009	876.17	1,018.95
12/31/2009	877.19	1,014.30
01/01/2010	878.13	1,010.00
02/01/2010	1,062.00	1,062.00
02/02/2010	1,063.59	1,063.59
02/03/2010	1,064.53	1,064.53
02/04/2010	1,064.97	1,064.97
02/05/2010	1,064.91	1,064.91
02/06/2010	1,064.52	1,064.52
02/07/2010	1,063.97	1,063.97
02/08/2010	1,063.33	1,063.33
02/09/2010	1,062.61	1,062.61
02/10/2010	1,061.87	1,061.87
02/11/2010	1,061.09	1,061.09

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(Cont.)

Table 9

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 6 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
02/12/2010	1,060.31	1,060.31
02/13/2010	1,059.53	1,059.53
02/14/2010	1,058.91	1,058.91
02/15/2010	1,058.66	1,058.66
02/16/2010	1,058.54	1,058.54
02/17/2010	1,058.43	1,058.43
02/18/2010	1,058.29	1,058.29
02/19/2010	1,058.11	1,058.11
02/20/2010	1,057.88	1,057.88
02/21/2010	1,057.58	1,057.58
02/22/2010	1,057.20	1,057.20
02/23/2010	1,056.72	1,056.72
02/24/2010	1,056.18	1,056.18
02/25/2010	1,055.59	1,055.59
02/26/2010	1,055.00	1,055.00
02/27/2010	1,054.39	1,054.39
02/28/2010	1,053.75	1,053.75
03/01/2010	1,053.08	1,053.08
03/02/2010	1,246.07	1,176.21
03/03/2010	1,283.26	1,213.62
03/04/2010	1,316.49	1,247.43
03/05/2010	1,347.23	1,278.82
03/06/2010	1,375.92	1,308.13
03/07/2010	1,403.09	1,335.89
03/08/2010	1,429.00	1,362.36
03/09/2010	1,453.79	1,387.70
03/10/2010	1,477.49	1,411.93
03/11/2010	1,500.08	1,435.05
03/12/2010	1,521.55	1,457.06
03/13/2010	1,548.47	1,482.12
03/14/2010	1,577.01	1,508.05
03/15/2010	1,605.87	1,534.02
03/16/2010	1,628.48	1,556.01
03/17/2010	1,647.59	1,575.49
03/18/2010	1,666.74	1,594.62
03/19/2010	1,684.99	1,612.92
03/20/2010	1,702.70	1,630.62
03/21/2010	1,719.79	1,647.69

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(Cont.)

Table 9

Sacramento Natural Gas Storage
Florin Gas Storage Field

Well 6 Flowing Bottom Hole Pressures

DATE	Well Bottom Hole Pressure (psi)	Well Block Pressure (psi)
03/22/2010	1,736.31	1,664.18
03/23/2010	1,752.27	1,680.10
03/24/2010	1,767.73	1,695.50
03/25/2010	1,782.75	1,710.43
03/26/2010	1,797.32	1,724.89
03/27/2010	1,811.49	1,738.92
03/28/2010	1,821.90	1,750.37
03/29/2010	1,821.90	1,754.90
03/30/2010	1,821.90	1,758.61
03/31/2010	1,821.90	1,761.78
04/01/2010	1,821.90	1,764.53
05/01/2010	1,821.90	1,792.08
06/01/2010	1,821.90	1,800.10
06/16/2010	1,821.90	1,801.56
07/01/2010	1,821.90	1,802.53
08/01/2010	1,295.75	1,295.75
09/01/2010	691.99	976.26
10/01/2010	916.42	967.65
11/01/2010	928.46	966.51
11/14/2010	1,047.75	1,047.75
12/01/2010	1,758.13	1,676.50
01/01/2011	1,821.90	1,786.07
02/01/2011	1,821.90	1,797.19
03/01/2011	1,821.90	1,800.41
03/04/2011	1,821.90	1,800.70
04/01/2011	1,821.90	1,802.35
06/01/2011	991.91	991.91
07/01/2011	937.86	1,001.48
07/27/2011	1,132.25	1,132.25

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(Cont.)

CERTIFICATE OF SERVICE

I hereby certify that I have this day served by electronic mail to each person listed on the attached service list, in accordance with Rules 1.9, and 1.10 of the Commission's Rules of Practice and Procedure, the **REPLY TESTIMONY OF BRUCE PALMER** submitted on behalf of Sacramento Natural Gas Storage, LLC.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Dated: October 3, 2008, at Sacramento, California.

_____/s/_____
Sandra J. Andrade

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(Cont.)

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CALIFORNIA PUBLIC UTILITIES COMMISSION
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Parties

PETER G. ESPOSITO
CRESTED BUTTE CATALYSTS, LLC
PO BOX 668
CRESTED BUTTE, CO 81224
FOR: LODI GAS STORAGE

JONATHAN BROMSON
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 4107
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: DRA

JEANNE B. ARMSTRONG
ATTORNEY AT LAW
GOODIN MACBRIDE SQUERI DAY & LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

LAW DEPARTMENT
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120-7442
FOR: PACIFIC GAS AND ELECTRIC COMPANY

DAN L. CARROLL
ATTORNEY AT LAW
DOWNEY BRAND, LLP
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO, CA 95814
FOR: LODI GAS STORAGE

DAVID A. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON, P.C.
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

JOHN V. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

TINA THOMAS
REMY, THOMAS, MOOSE AND MANLEY LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

EILEEN M. TEICHERT
CITY ATTORNEY

ALFRED F. JAHNS
LAW OFFICE ALFRED F. JAHNS

D2-292
(Cont.)

CITY OF SACRAMENTO
915 I STREET, ROOM 4010
SACRAMENTO, CA 95814-2604
FOR: CITY OF SACRAMENTO

3436 AMERICAN RIVER DRIVE, SUITE 12
SACRAMENTO, CA 95864
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

Information Only

KARI KLOBERDANZ
REGULATORY CASE ADMINISTRATOR
SOUTHERN CALIFORNIA GAS COMPANY
555 WEST 5TH STREET, GT14D6
LOS ANGELES, CA 90013-1011
FOR: SOUTHERN CALIFORNIA GAS COMPANY

MARCIE MILNER
DIRECTOR - REGULATORY AFFAIRS
SHELL TRADING GAS & POWER COMPANY
4445 EASTGATE MALL, SUITE 100
SAN DIEGO, CA 92121

JOHN W. LESLIE
ATTORNEY AT LAW
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
11988 EL CAMINO REAL, SUITE 200
SAN DIEGO, CA 92130

KATARZYNA M. SMOLEN
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B9A
SAN FRANCISCO, CA 94105

PAUL C. LACOURCIERE
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO, CA 94105

PETER V. ALLEN
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO, CA 94105-3606

JEANNE B. DAY
GOODIN, MACBRIDE, SQUERI, DAY&LAMPREY, LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE, LLC

MICHAEL B. DAY
ATTORNEY AT LAW
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

EDWARD O'NEILL
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
FOR: DAVIS WRIGHT TREMAINE LLP

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST. SUITE 303
SAN FRANCISCO, CA 94117

KERRY C. KLEIN
ATTORNEY AT LAW
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120
FOR: PACIFIC GAS AND ELECTRIC COMPANY

MRW AND ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND, CA 94612
FOR: MRW AND ASSOCIATES, INC.

ROCHELLE AMRHEIN
CITY OF SACTO, ENVIRONMENTAL PLANNING SV
300 RICHARDS BOULEVARD, 3RD FL
SACRAMENTO, CA 95811

ASHLE CROCKER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

CHRIS BUTCHER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

COLIN BAILEY
LEGAL SERVICES OF NORTHERN CALIFORNIA
515 12TH STREET
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

SAM R. ROPELATO
LEGAL SERVICES OF NORTHERN CALIFORNIA
515 12TH STREET
SACRAMENTO, CA 95814

MICHAEL T. SPARKS
SENIOR DEPUTY CITY ATTORNEY
CITY OF SACRAMENTO
915 I STREET, ROOM 4010

D2-292
(Cont.)

FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.

MAI A G. JACOBS
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428
FOR: AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION

THOMAS ENSLOW
ADAMS BROADWELL JOSEPH & CARDOZO
520 CAPITOL MALL, SUITE 350
SACRAMENTO, CA 95814-4715
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

RONALD LIEBERT
ATTORNEY AT LAW
CALIFORNIA FARM BUREAU FEDERATION
2300 RIVER PLAZA DRIVE
SACRAMENTO, CA 95833

ANN L. TROWBRIDGE
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DRIVE, SUITE 205
SACRAMENTO, CA 95864

SACRAMENTO, CA 95814-2604
FOR: CITY OF SACRAMENTO

SCOTT W. PINK
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428
FOR: AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION

SLIDER CONSTANCE
CO-CHAIR
AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.
5740 WILKINSON STREET
SACRAMENTO, CA 95824
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSOCIATION (AGENA)

STEVEN M. COHN
ASSISTANT GENERAL COUNSEL
SACRAMENTO MUNICIPAL UTILITY DISTRICT
PO BOX 15830
SACRAMENTO, CA 95852-1830

State Service

EUGENE CADENASSO
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

PAUL S. PHILLIPS
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5306
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RICHARD SMITH
CALIF PUBLIC UTILITIES COMMISSION
DIVISION OF ADMINISTRATIVE LAW JUDGES
ROOM 5007
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

JAMES W. REEDE JR., ED.D.
ENVIRONMENTAL SCIENCE PROFESSOR
1516 - 9TH STREET
SACRAMENTO, CA 95814

MICHAEL ROSAUER
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RICHARD A. MYERS
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: ENERGY DIVISION

ROBERT MASON
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5141
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

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APPENDIX 20

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

REPLY TESTIMONY OF

GEORGE F. DAMES

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail:ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: October 3, 2008

Q1 ***Please State Your Name And Business Address.***

My name is George F. Dames. My business address is Ryder Scott Company, L.P., 1100 Louisiana Street, Suite 3800, Houston, TX 77002.

Q2 ***What Is Your Current Occupation?***

Geologist and Managing Senior Vice President - Geoscience

Q3 ***Please Describe Your Educational Training.***

I received my Bachelor of Arts degree from Rice University in May, 1975.

Q4 ***Please Describe Your Career Path Up To The Present Time.***

My first position as a geologist was with Southern Natural Gas Company, where I worked as a Reservoir Geologist evaluating reserves of natural gas related to Southern's gas pipeline system from 1975-1979. After that, I took a position as Development Geologist with Texasgulf, Inc., where I spent two years directing and evaluating appraisal and development drilling for company properties located in the Gulf of Mexico. I subsequently did similar work for Texas General Resources, where I was also a development geologist responsible for directing and evaluating exploration, appraisal and development drilling for Texas General's properties in the Gulf of Mexico. In 1982, I took a position as exploration geologist at Andress Petroleum, where I developed and evaluated exploration prospects in the Gulf Coast. I also worked as an exploration geologist for Wagner & Brown Company, where I also developed and evaluated exploration prospects in the Gulf Coast. In 1993, I took a position with Ryder Scott, where I have performed reserve evaluation and reservoir studies worldwide.

Q5 ***What Are Current Your Job Responsibilities At Ryder Scott?***

As Managing Senior Vice President – Geoscience, I am responsible for the direction and technical oversight of all geoscience studies conducted within Ryder Scott. I am also directly involved in reservoir studies and reserves evaluations. I have also authored reserve training materials for several major oil companies focusing on the correct techniques for determining in place hydrocarbon volumes using the volumetric method. I have presented classes on these methods for several national and major oil companies

Q6 ***Is A True And Correct Copy Of Your Resume Attached As Exhibit A?***

Yes.

Q7 ***You Performed Work For SNGS Regarding The Proposed Natural Gas Storage Facility, Correct?***

Yes.

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Q8 ***Please Briefly Describe The Work You Performed?***

The geoscience group of Ryder Scott, which I oversee, was charged with determining the size and shape of the Florin Field and investigating the reservoir's suitability for gas storage. Initially, my involvement was to manage the personnel directly involved in the study. I have continued working with our simulation group providing detailed descriptions of the geology of the Florin Field in response to issues raised in response to the SNGS application to convert Florin to a gas storage field.

Q9 ***Have You Read The Rebuttal Testimony of John O. Robertson Submitted On Behalf of Avondale Glen Elder Neighborhood Association?***

Yes.

Q10 ***Did Mr. Robertson Identify Any Errors In Ryder Scott's Analysis That Give You Reason To Modify The Surface Boundaries Ryder Scott Delineated For The Florin Field?***

No.

Q11 ***Dr. Robertson Relies On An Interpretation Of The Field Prepared By Reid, Are You Familiar With The Reid Study?***

I am not aware of any study by Reid.

Q12 ***Do You Agree With Dr. Robertson's Characterization of The Reid Study?***

As stated above, I have not seen any study by Reid. However, the figures described in Dr. Robertson's testimony appear to coincide with figures that were attached to Lowell Garrison's field study of Florin Field published in March, 1993. Dr. Robertson refers to Reid's figure 3 as a structure map and Reid's figure 4 as an isopach map. Figures 3 and 4 in the Garrison report are a structure map of the top of the Winters Sand (the productive interval in Florin Field) and an isopach of the total sand thickness of the Winters Sand.

Q13 ***In Your Opinion, Does The Reid Study Provide A Persuasive Interpretation Of The Florin Field?***

If we accept that the figures Dr. Robertson refers to as the Reid report are the same as those attached to the Garrison report, I am of the opinion that the figures (and the text in the Garrison report) are a reasonable description of Florin Field. However, Dr. Robertson's interpretation of those figures is incorrect.

Dr. Robertson states that the maps "show the capability of gas and/or water to flow between the dome structure and the channel sand since there is no fault or other barrier shown." The Winters channel does extend to the northeast as depicted in Garrison's figure 4. However the gas accumulation does not. In July, 1983, TXO Production

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(Cont.)

Corporation logged the Northgate Beneficial #35-1 well in Section 35, Township 8 North, Range 5 East approximately 2500' northeast of the Florin discovery well, Union Oil Florin #1. As shown on Garrison's figure 3 the well encountered a thick (100' +), well developed Winters Sand at an elevation of -3485 true vertical depth subsea (TVDSS). The Winters Sand in the well is clearly water wet on the log and the well was abandoned. In December, 1983, Quadren (later Procter & Gamble) logged the Florin #2 well in Section 34, Township 8 North, Range 5 East approximately 3928' southwest of the TXO well. This well found the upper member of the Winters Sand full of gas to an elevation of -3765 TVDSS. Since gas does not occur downdip of water in continuous reservoirs there is clearly a barrier between the TXO well and the Quadren Florin #2 well.

A detailed review of the well logs shows that the gas containing members of the Winters Sand (the Florin reservoir interval) thin and eventually disappear moving from southwest to northeast across the field. This sand "pinchout" in the updip direction is what caused the gas accumulation in Florin Field. These types of combination stratigraphic / structural traps are common across the entire Central Valley of California. In an assessment of the Sacramento Basin Province for the USGS, Magoon and Valin state that of 47 fields found in this particular trend 36 are combination traps.

Q14 ***Please Describe The Process By Which Ryder Scott Delineated The Surface Boundaries of the Florin Field?***

As depicted on Garrison's structure map of the top of the Winters Sands, the Florin Field is situated generally on a southwest plunging nose. Ryder Scott was able to confirm this general structural configuration using the well logs to determine the top of the formation at each point of the reservoir intercepted by a well. Further, Ryder Scott had access to seismic data which also confirmed the general southwest dipping trend of the reservoir. The seismic data also indicated an anomalous response in the vicinity of the thick gas sands seen by the producing wells. This anomaly in the seismic data is not observed to the south of the field where the Venada Anderson well found no sand nor to the northeast where the TXO Northgate well found no gas. Ryder Scott used the net pay thicknesses observed in the wells and the shape of the seismic anomaly to control the thickness of the reservoir. When the net sand map derived from this information is combined with the structural position of the gas / water contact, the boundaries of the field can be estimated. It is important to note that the field is limited to the northeast by the wet TXO well, to the south by the Venada Anderson well which found no reservoir and to the southwest by the Union Florin #4 well which found a limited gas column on water.

Q15 ***Is The Process You Just Described One That Is Generally Used In Profession For Delineating Surface Boundaries Of Gas Fields Like The Florin Field?***

Yes.

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Q16 ***What Source Materials Did You Use To Determine The Gas Water Contact For The Florin Field?***

The Gas/Water contact was determined from the logs. A clear difference in the resistivity measurement is observed between the gas bearing sands and the water bearing sands. The performance of the wells confirmed our estimate of the location of the contact.

Q17 ***Is It Possible To Determine From Those Materials The Depth of The Florin Field's Gas Sands?***

Yes.

Q18 ***Did Ryder Scott Determine The Depth of The Florin Field's Gas Sands As Part Of Its Work To Delineate The Field's Surface Boundaries?***

Yes. As discussed above, the depth of the gas sands were determined from the well logs and corrected for the deviation of the wells from vertical.

Q19 ***What Did Ryder Scott Determine In That Regard?***

The well log and seismic data could be combined to prepare a reasonable interpretation of the shape of the Florin Field gas reservoir and the gas volume in the reservoir determined in this manner is consistent with the production history of the field.

Q20 ***What Is Your Degree of Confidence In The Surface Boundaries Ryder Scott Delineated For The Florin Field?***

The surface boundaries delineated for the Florin Field represent our best estimate of the subsurface structure of the field, translated to the surface, using standard methodologies based on the best information available to us. My department's analysis is supported by our simulation work, where we achieved a good history match.

Q21 ***Do You Agree With Dr. Robertson's Criticism That Mr. Matthews Should Have "Decreased The Thickness Of The Reservoir To 10 Feet And Increased The Footprint By A Factor Of 2.5"?***

No. I defer to Bruce Palmer's discussion of the operational reasons why operators may only perforate the upper section of reservoirs when communication with an underlying reservoir is possible.

As noted in Garrison's report, the Florin gas reservoir consists of stacked channel sands which Garrison has annotated from top to bottom as "A" through "C". The cleaner, gas-filled portions of these sands show clear response on the logs; a low gamma ray reading and a high resistivity reading. The gamma ray logs and sample logs (mud logs) also show

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that the intervals between these higher quality sands are not shales but lower quality sand and silts. The gas / water contacts observed in the wells is consistent across all zones; most notably in the Union Florin #4 at the southwest end of the field where the contact is seen in the "A" interval and the Union Florin #1 at the northeast end of the field which is gas to base in the "C" interval. A common contact generally indicates that all the sand members are in vertical communication and can be produced through perforations in the uppermost part of the sand only. The operators' practice of completing only in the uppermost part of the sand in this field indicates they believed the zones were in vertical communication. The subsequent behavior of the wells confirms that the zones are in communication. Dr. Robertson's proposal to restrict the reservoir thickness to only the perforated interval is contrary to common industry practice.

Q22 ***Is Dr. Robertson Correct When He States At Page Six Of His Testimony That "Only An Average Of 10 Feet Of The Upper Interval Has Ever Been Produced By The Oil Companies[.]"***

No. Dr. Robertson's contention that perforation thickness defines sand thickness is incorrect. Vertical communication in the Florin field allows wells to drain volumes below the 10 foot perforated interval. This vertical communication is clearly demonstrated by the Venada Lindsey #1 well in Section 34, Township 8 North, Range 5 East. This well logged the Florin reservoir interval in December, 1992, five years after the field had stopped producing due to water influx. The Lindsey well encountered a 100' thick section of the "A" member of the Florin reservoir at an elevation of -3728 TVDSS. The sand was swept by water as shown by the low resistivity log readings. However, a strong gas signature was observed on the Sonic log to a depth of -3792 (approximately the original Florin Field G/W contact). These log responses in combination indicate that the well intercepted the reservoir within the extent of the original gas accumulation and that production operations have clearly drained the entire 64' vertical gas interval originally in place at the well location. This vertical drainage occurred despite the presence of a low reservoir quality zone observed on the log in the middle of the reservoir. This log clearly demonstrates that Dr. Robertson's conclusion that there is poor vertical communication between the layers in the Florin reservoir is incorrect.

Q23 ***Do You Agree With Dr. Robertson's Statement, At Page Four of His Testimony, That "The Well Logs Show That ... There Is Very Poor Vertical Permeability As A Result Of The Layers Of Shale?***

No, as discussed above, the "shale" layers within the sands are not true shales but lower quality sand and silt. The Venada Lindsey well demonstrates that these lower quality intervals do not act as effective vertical barriers. Pressure information also indicates there are no horizontal permeability barriers within the field. Each of the gas bearing members of the Florin sand were perforated and produced in their most updip position; "A" in the P&G Florin #1, "B" in the Union Florin #2 and "C" in the Union Florin #1. Consequently, the vertical communication between the high quality sands across intervening lower quality silts is immaterial; all layers have been perforated. It should be

D2-293 (Cont.)

noted that the pressure behavior of the three wells mentioned indicate they are in communication despite being completed in different sand layers. There is no evidence that the intervening silty layers act as effective barriers and substantial evidence that they do not act as barriers.

Q24 ***Please Respond To The Following Assertion By Dr. Robertson: "Although The Ryder Scott Company's Computer Model Placed A Depositional Feature Within The Dome, Reid Did Not Recognize That There Was Such A Feature. This Is Important In That The Ryder Scott Company Model Only Injects Fluids Into A Portion Of The Dome, Thus Reducing Their Footprint By Almost One-Half."***

It is unclear whether Dr. Robertson is referring to the erosional reservoir termination on the southeast end of the field or the northwest-southeast trending feature between the Union Florin #1 and #2 wells and the remainder of the field to the southwest.

The reservoir termination to the southeast is depicted on Garrison's isopach as a zero sand line between the Florin Field and the Venada Anderson well. As discussed in response to question 14, the Anderson well found no sand in the reservoir interval. There is no reservoir present south of this line and this area is not included in the model.

The northwest-southeast trending feature between the Union Florin #1 and #2 wells represents the truncation of the "A" channel. The "A" member is present in wells southwest of this line but is not present in the Florin #1 and #2 wells. Reservoir volumes on both sides of this feature are included in the model. The model footprint therefore includes all of the original gas-filled reservoir volume.

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Q25 ***Please Summarize Your Response To Dr. Robertson's Testimony.***

Dr. Robertson has in many cases misstated Ryder Scott's work and has drawn conclusions not supported by the data. His assertion that the footprint of Florin Field must be substantially larger than that depicted in Ryder Scott's work is based on a faulty understanding of the nature of the hydrocarbon trap in Florin. His conclusions about the production mechanism within the field do not address the clear evidence of good communication within the reservoir demonstrated by the Venada Lindsey nor has he addressed the fact that each of the gas bearing members of the reservoir have been perforated. Dr. Robertson's assertion that vertical permeability is limited within the reservoir is not supported by the well logs nor field performance. Dr. Robertson has asserted that the field's extents must be greater but has not reconciled that statement with the known field limits as demonstrated by well log and seismic data.

Q26 ***Does That Conclude Your Reply Testimony?***

Yes.

EXHIBIT A

BIOGRAPHICAL DATA

GEORGE F. DAMES, Managing Senior Vice President, Reservoir Geologist

EDUCATION

BA degree, geology, Rice University, 1975
Industry-sponsored schools in well log evaluation and interpretation, sandstone reservoir exploration, reservoir evaluation and economic evaluation of producing properties

PROFESSIONAL ASSOCIATIONS

Member, American Association of Petroleum Geologists
Member, Houston Geological Society

SUMMARY OF EMPLOYMENT

Practicing as a petroleum geologist for more than 25 years with extensive experience in subsurface mapping, well log correlation and interpretation and reservoir characterization. Expertise in reconciliation of seismic, subsurface and engineering data. Involved in various field studies for reserves development and evaluation in multiple basins and lithologies worldwide. Conduct reservoir characterization for reservoir simulation studies. Experience with petrophysical interpretation software, including development of reservoir-specific models incorporating core, drill-stem-test and production data. Experience with geological mapping software.

Ryder Scott Co. LP 1993 to Present
Evaluate producing, non-producing and undeveloped oil, gas, and condensate reserves. Identify and perform volumetric evaluation of reserves through petrophysical, geological and geophysical methods. Prepare and review producing property sales packages for both buyers and sellers.

Selected Field Studies
Trinidad Gas Project, Trinidad and Tobago
Involved in reserves and resources evaluation of future national gas supply. Coordinated geoscience team of nine members. Developed consistent methodology in deterministic evaluation of developed gas reserves and probabilistic evaluation of potential gas reserves. Developed risk-adjusted future gas production profile.

Elk Hills field, Kern County, California
Involved in reserves evaluation of and determined exploitation potential of the western 31S and main body B sands. Estimated and reconciled original oil in place, cumulative production and injection and remaining gas and oil in place in a thick, turbiditic sandstone sequence that had been produced under gas injection and waterflooding through multiple, commingled completions. The original and current fluid contacts could not be identified on well logs. This study resolved the contacts using log, core and drill-stem-test data as well as reservoir production and pressure history. The new interpretation explained apparent

"excess" gas in the reservoir and resulted in the identification of multiple recompletion and infill drilling opportunities.

Western Desert Gas Project, Egypt
Assisted in reserves and development-plan evaluation of multi-field concession. Developed stratigraphic correlation scheme of fluvial to delta-front sandstones consistent with available production and pressure data. Constructed petrophysical model of Cretaceous and Jurassic age sandstone reservoirs that accounted for results of production and drill-stem-test data. Developed wellbore utilization scheme to maintain production at desired "plateau" level for maximum duration.

Tyumen Oil, Orenburgneft Production Association
Involved in reserves audit and categorization. Evaluated FSU "A, B, C1 and C2" reserves designations and development of risked production profiles based on "proved, probable, possible and potential" reserve categories of Society of Petroleum Evaluation Engineers. Developed optimized exploitation program based on risk-adjusted future net income.

Raudhatain and Sabiriyah fields, Kuwait
Assisted in audit of original oil in place estimates and procedures. Demonstrated that trapping mechanism is related more to permeability degradation than to structure. New interpretation suggested that apparent water-level conflicts may have resulted from overly optimistic porosity cutoffs and that a more complex stratigraphic model of the reservoir was unnecessary.

Completed field and reserve studies in the Cabimas Field, Lake Maracaibo Area, Venezuela, Cusiana / Cupiagua Fields, Colombia and the Casanare Association Area in Colombia.

Simulation Studies
West Clear Lake gas storage field, Harris County, Texas
Constructed structure and gross and net sand isopach maps used in reservoir simulator for water-drive gas storage field in massive, clean sands of the Frio formation. Developed correlations and cross sections to demonstrate vertical seals and possible areas of communication between reservoir zones.

Dos Cuadras waterflood, offshore California
Proposed waterflood in Miocene sandstones on thrust-fault-related structure. Constructed structure maps accounting for seismically identified reverse and normal faulting of magnitudes ranging from 25 to 500 feet as well as normal faults identified from subsurface correlation not resolvable on seismic.

Fanny field, Oriente basin, Ecuador
Constructed structure and isopach maps. Developed correlation of individual sand bodies deposited in a fluvial environment. Developed structure maps relating seismic marker to top of reservoir structure. Final structure accounted for overprint of sandstone compactional features on basement-related folding.

Consulting Reservoir Geologist, Houston 1991 to 1993
Conducted field studies reconciling reservoir performance to geological and geophysical reservoir descriptions. Evaluated recompletion, infill drilling and exploration opportunities.

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Wagner and Brown, Houston 1985 to 1991
Exploration geologist developing and screening exploratory prospects in the Gulf Coast, east Texas and the Midcontinent. Conducted structural and stratigraphic studies of producing trends through aerial photography, subsurface, seismic and gravity data interpretation. Presented proposed development and exploration wells to industry partners. Drilled two exploration prospects with one discovery and three successful development locations.

Andress Petroleum, Houston 1982 to 1985
Exploration geologist developing drilling prospects in the Texas and Louisiana gulf coast through regional subsurface mapping. Developed, acquired and promoted four prospects to industry, one discovery.

Texas General Petroleum Company, Houston 1981 to 1982
Manager of geological engineering-offshore. Directed geological assessments of proposed exploratory drilling program in Louisiana state waters. Designed mudlogging, wireline logging, coring and testing programs for all company-operated wells in the region. Provided reserves estimates and development plans for field discoveries.

Texasgulf Oil and Gas Company, Houston 1979 to 1981
Exploration geologist evaluating blocks available in federal offshore lease sales. Advanced to regional development geologist-Gulf of Mexico. Managed ongoing evaluation, delineation and exploitation of multiple producing fields across the federal waters of the Gulf of Mexico. Responsible for platform locations, development well planning and wellbore utilization. Presented development locations to management and industry partners. Represented company in unitization of offshore field with competitive leases.

Southern Natural Gas Company, Houston 1975 to 1979
Geologist promoted to senior geologist. Estimated proved, probable, and possible reserves and expected deliverability from prospective sources of supply along the company's pipeline system. Conducted ongoing reconciliations of estimates of gas supplies and production trends from contracted sources. Committee member of American Gas Association Gas Reserve Committee. Coordinated expansion of pipeline capacity with producers' estimates of increased supply from exploratory and development drilling programs.

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GEOGRAPHICAL AREAS OF EXPERIENCE

U.S. Federal Offshore - Gulf of Mexico/Texas to Louisiana
U.S. Gulf Coast Tertiary Trends - Miocene, Frio, Yegua, and Wilcox/South Texas to Southeast
Louisiana
California – Thermal Projects, Offshore Pleistocene, Pliocene and Miocene Sands and Monterrey
Mississippi and Alabama – Mesozoic Trends
East Texas Basin
Arkoma Basin
Argentina, Bolivia, Colombia, Ecuador, Brazil, Venezuela
North Louisiana
Western Siberia, Russia, Ukraine
China
Kuwait

Egypt
Trinidad and Tobago
Offshore West Africa
Indonesia

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served by electronic mail to each person listed on the attached service list, in accordance with Rules 1.9, and 1.10 of the Commission's Rules of Practice and Procedure, the **REPLY TESTIMONY OF GEORGE DAMES** submitted on behalf of Sacramento Natural Gas Storage, LLC.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Dated: October 3, 2008, at Sacramento, California.

_____/s/_____
Sandra J. Andrade

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(Cont.)



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ies

PETER G. ESPOSITO
CRESTED BUTTE CATALYSTS, LLC
PO BOX 668
CRESTED BUTTE, CO 81224
FOR: LODI GAS STORAGE

JONATHAN BROMSON
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 4107
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: DRA

JEANNE B. ARMSTRONG
ATTORNEY AT LAW
GOODIN MACBRIDE SQUERI DAY & LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

LAW DEPARTMENT
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120-7442
FOR: PACIFIC GAS AND ELECTRIC COMPANY

DAN L. CARROLL
ATTORNEY AT LAW
DOWNEY BRAND, LLP
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO, CA 95814
FOR: LODI GAS STORAGE

DAVID A. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON, P.C.
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

JOHN V. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

TINA THOMAS
REMY, THOMAS, MOOSE AND MANLEY LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

[redacted] M. TEICHERT
CITY ATTORNEY

ALFRED F. JAHNS
LAW OFFICE ALFRED F. JAHNS

CITY OF SACRAMENTO
915 I STREET, ROOM 4010
MENTO, CA 95814-2604
TTY OF SACRAMENTO

3436 AMERICAN RIVER DRIVE, SUITE 12
SACRAMENTO, CA 96864
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

Information Only

KARI KLOBERDANZ
REGULATORY CASE ADMINISTRATOR
SOUTHERN CALIFORNIA GAS COMPANY
555 WEST 5TH STREET, GT14D6
LOS ANGELES, CA 90013-1011
FOR: SOUTHERN CALIFORNIA GAS COMPANY

MARCIE MILNER
DIRECTOR - REGULATORY AFFAIRS
SHELL TRADING GAS & POWER COMPANY
4445 EASTGATE MALL, SUITE 100
SAN DIEGO, CA 92121

JOHN W. LESLIE
ATTORNEY AT LAW
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
11988 EL CAMINO REAL, SUITE 200
SAN DIEGO, CA 92130

KATARZYNA M. SMOLEN
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B9A
SAN FRANCISCO, CA 94105

PAUL C. LACOURCIERE
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO, CA 94105

PETER V. ALLEN
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO, CA 94105-3606

JEANNE B. DAY
GOODIN,MACBRIDE,SQUERI,DAY&LAMPREY,LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
F WILD GOOSE STORAGE, LLC

MICHAEL B. DAY
ATTORNEY AT LAW
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

EDWARD O'NEILL
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
FOR: DAVIS WRIGHT TREMAINE LLP

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST. SUITE 303
SAN FRANCISCO, CA 94117

KERRY C. KLEIN
ATTORNEY AT LAW
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120
FOR: PACIFIC GAS AND ELECTRIC COMPANY

MRW AND ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND, CA 94612
FOR: MRW AND ASSOCIATES, INC.

ROCHELLE AMRHEIN
CITY OF SACTO, ENVIRONMENTAL PLANNING SV
300 RICHARDS BOULEVARD, 3RD FL
SACRAMENTO, CA 95811

ASHLE CROCKER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD
ASSN. (AGENA)

CHRIS BUTCHER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD
ASSN. (AGENA)

COLIN BAILEY
LEGAL SERVICES OF NORTHERN CALIFORNIA
515 12TH STREET
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD
ASSN. (AGENA)

R. ROPELATO
SERVICES OF NORTHERN CALIFORNIA
515 12TH STREET
SACRAMENTO, CA 95814

MICHAEL T. SPARKS
SENIOR DEPUTY CITY ATTORNEY
CITY OF SACRAMENTO
915 I STREET, ROOM 4010

D2-294
(Cont.)

FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.

MAT A G. JACOBS
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428
FOR: AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION

THOMAS ENSLOW
ADAMS BROADWELL JOSEPH & CARDOZO
520 CAPITOL MALL, SUITE 350
SACRAMENTO, CA 95814-4715
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

RONALD LIEBERT
ATTORNEY AT LAW
CALIFORNIA FARM BUREAU FEDERATION
2300 RIVER PLAZA DRIVE
SACRAMENTO, CA 95833

ANN L. TROWBRIDGE
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DRIVE, SUITE 205
SACRAMENTO, CA 95864

SACRAMENTO, CA 95814-2604
FOR: CITY OF SACRAMENTO

SCOTT W. PINK
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428
FOR: AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION

SLIDER CONSTANCE
CO-CHAIR
AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.
5740 WILKINSON STREET
SACRAMENTO, CA 95824
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSOCIATION (AGENA)

STEVEN M. COHN
ASSISTANT GENERAL COUNSEL
SACRAMENTO MUNICIPAL UTILITY DISTRICT
PO BOX 15830
SACRAMENTO, CA 95852-1830

State Service

EUGENE CADENASSO
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

PAUL S. PHILLIPS
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5306
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RICHARD SMITH
CALIF PUBLIC UTILITIES COMMISSION
DIVISION OF ADMINISTRATIVE LAW JUDGES
ROOM 5007
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

JAMES W. REEDE JR., ED.D.
ENVIRONMENTAL SCIENCE PROFESSOR
1516 - 9TH STREET
SACRAMENTO, CA 95814

MICHAEL ROSAUER
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RICHARD A. MYERS
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: ENERGY DIVISION

ROBERT MASON
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5141
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

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(Cont.)

APPENDIX 21

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

REPLY TESTIMONY OF

ERIC F. HADSELL

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail:ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: October 3, 2008

Q1 ***Please State Your Name And Business Address.***

Eric Frank Hadsell; my business address is 14 North Orange Avenue, Lodi, California.

Q2 ***What Is Your Current Occupation?***

I am the owner of P.O.E. Inc., and provide operators with the latest in drilling, completion, and production optimization engineering including the selection, design and execution of hydraulic fracturing opportunities, artificial lift design, extreme low pressure gas production, and other specialized projects.

Q3 ***Please Describe Your Educational Training.***

I received a B.S. degree in petroleum engineering from the Colorado School of Mines in 1981. I have under taken specialized training programs in stimulation, sand control, well control, O&G Safety, artificial lift and others.

Q4 ***Please Describe Your Work Experience.***

My work experience is described in my resume, a copy of which is attached as Exhibit A.

Q5 ***Have You Ever Been Employed By The Ryder Scott Company?***

No.

Q6 ***Describe Your Involvement With Sacramento Natural Gas Storage, LLC.***

I was first engaged by SNGS on October 1, 2008 when I was asked to respond to certain assertions made by John O. Robertson in testimony he submitted on behalf of Avondale Glen Elder Neighborhood Association. I have had no prior affiliation with SNGS.

Q7 ***Please Generally Describe Your Assignment?***

I was asked to respond to Mr. Robertson's assertions that the reservoir's productive gas sands are approximately 10 feet deep.

Q8 ***What Are Well Casing Perforations?***

Perforations are holes made through the casing and cement of the well and into the reservoir formation. They are the flow path from the formation into the wellbore in a cased and cemented well completion.

Q9 ***What Is The "Reservoir Height"?***

The vertical dimension of the producible oil and/or gas in a reservoir.

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Q10 ***How Many Wells Produced Gas From the Florin Field?***

According to public records maintained on the website of the Division of Oil, Gas, and Geothermal Resources (DOGGR), five wells produced gas from the Field.

Q11 ***In The Five Wells Which Have Produced From The Winters Formation In The Florin Gas Field, Is The Reservoir Height Defined By The Perforated Interval?***

No. The reservoir height, as seen on the open hole logs (including mud logs), averages approximately 37 feet. Three of the wells were drilled directionally. Correcting the reservoir heights from measured depth ("MD", as measured along the course of the wellbore to true vertical depth), the average height of the reservoir is reduced to approximately 31 feet. Most of the wells were perforated 5' to 10' into the top of the reservoir to minimize (delay) the effect of water encroachment or water coning.

Q12 ***Please Describe How You Made That Determination From The Open Hole Logs.***

The five wells were logged with spontaneous potential ("SP") and resistivity logs, with the exception of the Union Oil & Gas Florin No. 4, where a gamma-ray log was substituted for the SP, and mud logs. The SP log records the direct current potential between a moving electrode in the wellbore and a fix surface electrode. It is used to distinguish permeable from impermeable rock and give a qualitative/relative indication of shale content. Resistivity logs measure the electrical resistivity of an interval; shale and porous rock with high salt water saturations are less resistive than rock with high gas or oil saturations. The gamma-ray log records the level of naturally occurring gamma rays which are more abundant in shales than in sands or carbonate rocks. The gamma-ray is used to determine the relative shale content of an interval.

P & G Florin No. 1: Similarly, the top of the reservoir is 3,755' MD, the bottom 3,830' MD, and 30' excluded for low resistivity and/or higher shale content. The net reservoir height is 3,830' – 3,755' – 30' = 45'.

P & G Florin No. 2: The reservoir top is 3,850' MD, the bottom is 3,900' MD; the net reservoir height is 50'.

Union Oil & Gas Florin No. 1: The reservoir top is 3,880' MD, the bottom is 3,910' MD, the net reservoir height is 30'.

Union Oil & Gas Florin No. 2: At 4,250' MD the SP increases dramatically (45 mv) and the resistivity increases from the shale baseline of 3 ohm-m to 11 ohm-m. This is the top of the gas reservoir. The gas/water contact is revealed by the reduction in resistivity at 4,290' MD. The overall height of the reservoir is 4,290' – 4,250' = 40'. The net height, excluding the lower resistivity interval between 4,275' and 4,285', is 10' less, or 30'.

Union Oil & Gas Florin No. 4: The top of the reservoir is indicated by lower readings on the gamma-ray log and higher (~9 ohm-m) on the resistivity at 5,420' MD. The

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resistivity drops to 3+ ohm-m at 5,430' MD. Because the gamma-ray at 5,430 MD remains low, the reduction in the resistivity is due to a change in the reservoir fluid (from resistive gas to conductive salt water). The base of the reservoir in this well is therefore a gas/water contact at 5,430'and the reservoir height is 5,430'- 5,420 =10'.

Q13 ***Is Perforating Only The Top Few Feet Of The Reservoir A Common Completion Technique?***

Yes. This is a very common practice in Northern California and oil/gas fields around the world. Producers commonly perforate less than the entire reservoir to minimize the effect of water encroachment. Similarly, oil reservoirs with a gas cap and water leg are most often perforated only in the middle of the oil leg to selectively produce the oil and limit water and gas coning.

Q14 ***Mr. Robertson's Testimony (Page 5, Paragraph 1) States That Perforating Only The Top Of The Reservoir Causes Production To Be Restricted To Gas Opposite The Perforations. He Further States That Shale Stringers In The Gas Reservoir Have "Prevented Its Vertical Migration" (Page 4, Paragraph 2). Are These Assertions Correct?***

No. The well logs do reveal the presence of shale stringers, as Dr. Robertson asserts. But they do *not* show the lateral continuity needed for the stringers to act as a barrier to vertical gas movement.

Q15 ***In Paragraph 3 (Page 5) Mr. Robertson Mentions A "Low 14-40 Percent Ultimate Recovery Or Displacement For Solution Gas Drive Reservoirs" Then Continues "Or 20 To 30 Percent Ultimate Recovery For Gas Cap Drive Reservoirs". Are These Reasonable Comparisons To The Florin Field Reservoir?***

No. These low recoveries are in carbonate oil reservoirs with a solution gas drive or a gas cap drive. The Winters reservoir in the Florin field is by any definition a dry gas reservoir with some water drive energy assisting an otherwise "depletion drive" reservoir. It is not a carbonate reservoir. The DeMatei No. 1, another dry gas Winters well in Sacramento county, had an initial reservoir pressure of roughly 4,000 PSI reduced to about 200 PSI, a recovery factor in the neighborhood of 95%. The production records for this well are available on the DOGGR website.

Q16 ***In Your Opinion, Would A Reasonably Capable Petroleum Engineer, Licensed By The State Of California, Have Concluded That The Depth Of The Florin Reservoir Was Only 10 Feet After Reviewing The Florin Field's Well Logs?***

No. As stated above, the well logs show that the average depth of the reservoir is 31 feet deep. The well logs also clearly show that the well perforations are at the very top of the formation, not at the bottom. Given these data, it is very puzzling that someone with Dr. Robertson's credentials would assert that the gas sands were only 10 feet deep.

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Q17 ***Are The Figures Dr. Robertson Includes In His Testimony, Regarding The Amount of Gas Shown By DOGGR To Have Been Produced From The Florin Field, Correct?***

No. On page three of his testimony, Dr. Robertson states:

> My review of the water and gas production for the 7 wells drilled in the Florin Gas Field, based upon data at the Division of Oil, Gas, & Geothermal Resources (DOGGR), reveal that these wells produced 8.69 MMSCF (million standard cubic feet) gas is or about 77 MCR (1000 cubic feet)

Assuming that Dr. Robertson meant to say "billion" instead of "million", his 8.69 figure is incorrect. I checked the DOGGR website and found the information included in the table below, which show that 7.878 billion cubic feet of gas was produced from the Florin Field.

WELL NAME	GAS PRODUCED (MSCF)	WATER PRODUCED (BBL)
Union Oil & Gas Florin No. 1	2,644,007	8,695
P & G Florin No. 1	2,212,576	63,913
Union Oil & Gas Florin No. 2	1,974,833	47,919
Union Oil & Gas Florin No. 4	141,984	20,507
P & G Florin No. 2	904,379	310
TOTAL	**7,877,779**	**141,340**

The 7.878 BSCF (billion standard cubic feet, 14.7 PSI & 65°F) recovered is 907 times *more* than the 8.69 MMSCF included in Mr. Robertson's testimony.[1]

Q18 ***Is It Your Understanding That DOGGR's Production Records For The Florin Field Are Incomplete?***

Yes. It is my understanding that several months of production data for several wells was missing from the DOGGR database. SNGS has provided me with corrected information showing that the total amount of gas produced from the Florin Field is 8.28 BSCF.

Q19 ***Are The Figures Dr. Robertson Includes In His Testimony, Regarding The Amount of <u>Water</u> Shown By DOGGR To Have Been Produced From The Florin Field, Correct?***

No. The figure listed on DOGGR's website for the amount of water produced is 141,340 BBL. That figure converts to 793,624 cubic feet, which is roughly 12 percent of the volume of water that Dr. Robertson asserts was produced from the Field.

D2-295 (Cont.)

[1] Mr. Robertson may have confused the units he used in quantifying gas volumes. 1,000 SCF is abbreviated as 1 MSCF, 1,000,000 as 1 MMSCF, and 1,000,000,000 as 1 BSCF.

Dr. Robertson also states at page 4, paragraph 3 of his testimony that "the greatest contributor to voidage was not the gas produced, but rather the produced water". In fact, when pressure, temperature, and the non-ideal nature of natural gas are used to convert the volume of gas produced at *standard* conditions to *reservoir* conditions (1,668 PSI and ~127°F), the volume of the gas is reduced to 71,318,341 cubic feet at *reservoir* conditions. The water production constitutes about 1.1% of the total volume of reservoir fluids produced. Doctor Robertson's statements regarding the amount of water produced from the Field thus reflect gross calculation errors.

D2-295 (Cont.)

Q20 ***Does That Conclude Your Testimony?***

Yes.

EXHIBIT A

Eric Frank Hadsell
Office: 209-365-1607
Cell: 707-249-4765
E-mail: efhadsell@comcast.net
14 North Orange Ave., Lodi, CA 95240

Qualifications:
Ethical and successful in twenty-six years of Oil and Gas operations, the last eight in Northern California. Other areas worked include East, South and North Texas, Gulf of Mexico, Colorado, Utah, Permian Basin, and Mississippi. Technically accomplished in completions, workovers, reservoir evaluation, artificial lift, drilling (well design and operations), surface facility design including pipeline design and compression, and acquisitions. All past responsibilities have required me to divide my time between several simultaneous projects.

Work Experience:
Continuously employed in O&G Operations from 1981 to present: DALEN Resources (and predecessors) in various locations from 1981 through August of 1995, Coho Resources from August 1995 through February 1997, Mitchell Energy/Devon from March 1997 to October 1999, Sheridan/Calpine/Rosetta from October 1999 to May 2007. Opened P. O. E. Inc. in May 2007.

Owner, P. O. E. Inc.: Incorporated in May 2007 to provide operators with the latest in drilling, completion, and production optimization engineering including the selection, design and execution of hydraulic fracturing opportunities, artificial lift design, extreme low pressure gas production, and other specialized projects.

Director of Operations, Sac Valley, Rosetta Resources: (Rio Vista CA: 10/99 to 5/07):
Directed all surface and cased hole operations in Northern California. Managed an operations and production staff of 20 plus personnel. Supervised drilling through 2002.

- Working with an exploration/development staff expanded production from Rosetta's CA operations from 28 MMCFPD in 1999 to 100 MMCFPD in March 2003, current production is 55 MMCFPD.
- Initiated northern California's first successful fracture program and successfully expanded that program from the Capay into several other low permeability intervals. This is an ongoing program.
- Designed and directed the installation of a ~20 mile gathering system with ~7,500 HP of centralized compression.
- As part of a small Rosetta team successfully negotiated the purchase of the 63 mile Rio Vista Gas Gathering system from PG&E (currently in due diligence).
- Negotiated a "New Gas Ordinance" covering O&G operations within the city of Rio Vista Municipal Code.

Staff Engineer, Mitchell Energy (Fort Worth, TX: 3/97 to 10/99): Responsible for production operations (completions, recompletions, workovers, artificial lift and compression) for several hundred wells in the Boonsville Bend (primarily Atoka gas) field in and around Bridgeport Texas (Wise County).

Area Engineer, Coho Resources (Dallas, TX: 8/95 through 2/97): Team leader responsible for all production/exploitation and reservoir operations in the Summerland, Bentonia, and Merit Fields; 55 total wells. These high permeability, multiple pay, low gravity oil, and natural water drive fields are in the Mississippi Salt Basin. As team leader I was responsible for reserve evaluation and budgeting. Designed and supervised the completion of three horizontal sidetracks.

- As team leader of an experienced exploitation team, increased production by 30% in the Summerland Field, (Jones Co., MS) using detailed reservoir evaluation and log analysis to develop optimal completion techniques and lift systems. Summerland normally declines by 35%/yr. and was the only Coho Oil field to exceed the companies 1996 production goals.
- Designed approximately fifty recompletions and workovers in the thirty year old Summerland Field achieving an economic success rate of 70%.

- Designed the first fracture stimulation in the Summerland Field. Post stimulation production exceeded expectations and the success of this procedure lead to similar Paluxy formation recompletions and workovers.
- Designed and provided onsite supervision for the drilling and completion of three horizontal sidetracks in the Tuscaloosa formation.

Senior Petroleum Engineer, DALEN Resources (Dallas, TX: 7/89 through 8/95): Designed all cased hole operations for 116 wells in the Logansport (DeSoto Parish, LA), Bald Prairie (Limestone Co., TX), Provident City (Colorado and Lavaca Co.'s, TX) fields and scattered wells and fields in the Permian Basin. Prepared reserve estimates and economic evaluations for all operations in these areas prior to execution.

- Designed and supervised fracture stimulations in a ~twenty gas well (13,000' overpressured) completion and stimulation program in the Bald Prairie Field (Cotton Valley Lime, Robertson Co., TX). The program exceeded the high economic expectations and was under budget.
- Designed the completions/recompletions and supervised the fracture stimulation's of six multiple horizon Hosston wells (four fracture stimulation's per well) in the Logansport (La) Field. Four wells were drilled based on recompletion results, three came in under budget. All four wells exceeded predicted production. In two years the Logansport field was transformed from a plugging liability to DALEN's most valuable (PV10) asset.
- Designed the 4 1/2" scab liners successfully run in 5 1/2" casing in the Knox City (≈5,000') and Vealmore (8,000') fields in the Permian Basin.
- Designed and executed a four well workover and stimulation program in the Provident City Field (geopressured, 12% CO2, Wilcox, Colorado Co., TX). Production from the four wells was doubled.
- Created a spreadsheet based wellbore diagram system that was selected for company wide use over similar commercial software.
- Initiated a field review program that became the company standard.

Petroleum Engineer (Concord and Fairfield, CA: 10/87 through 6/89): Directed completion, recompletion and workover operations for forty Northern California (primarily Forbes and Starkey formations) normally pressured, high permeability gas wells.

- Achieved a 90% economic success (based on <6 month payout) rate in approximately 30 recompletions and workovers.
- Reduced field wide compression costs by optimizing compressor size, introducing three stage compression, and commingling wells for compression where possible.
- Developed a spreadsheet based single entry production accounting system.

Lead Engineer (Vernal, UT: 11/84 through 9/87): Managed a production staff of three engineers and fifteen field personnel.

- Directed the daily drilling, completion, workover, and production operations in the Fontenelle (Lincoln Co. WY), Echo Springs (Sweetwater Co. WY) and Pleasant Valley and Glen Bench (Uintah Co. UT) fields.
- Designed and oversaw the installation of a twenty-five well, multiple compressor casing head gas gathering system in the Pleasant Valley Field, Uintah Co., Utah

Petroleum Engineer (Denver, CO: 6/83 through 10/84): Directed drilling operations in the Green River Basin, Powder River Basin and the Wyoming Overthrust belt.

- Designed and installed a seven well condensate gathering and stabilization system in the Echo Springs Field.

Drilling Supervisor: (Rock Springs, WY: 1/82 through 5/83): Provided onsite drilling and completion supervision for operations in the Overthrust belt, Powder River, and Green River Basins.

Education:

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- Graduated with a BS in Petroleum Engineering from the Colorado School of Mines in 1981.
- Various specialized training including stimulation, sand control, well control, O&G Safety, artificial lift and others.
- Member: SPE, AADE, CIPA and SPA

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(Cont.)

CERTIFICATE OF SERVICE

I hereby certify that I have this day served by electronic mail to each person listed on the attached service list, in accordance with Rules 1.9, and 1.10 of the Commission's Rules of Practice and Procedure, the **REPLY TESTIMONY OF ERIC HADSELL** submitted on behalf of Sacramento Natural Gas Storage, LLC.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Dated: October 3, 2008, at Sacramento, California.

_____/s/_____
Sandra J. Andrade

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(Cont.)

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

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ies

PETER G. ESPOSITO
CRESTED BUTTE CATALYSTS, LLC
PO BOX 668
CRESTED BUTTE, CO 81224
FOR: LODI GAS STORAGE

JONATHAN BROMSON
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 4107
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: DRA

JEANNE B. ARMSTRONG
ATTORNEY AT LAW
GOODIN MACBRIDE SQUERI DAY & LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

LAW DEPARTMENT
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120-7442
FOR: PACIFIC GAS AND ELECTRIC COMPANY

DAN L. CARROLL
ATTORNEY AT LAW
DOWNEY BRAND, LLP
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO, CA 95814
FOR: LODI GAS STORAGE

DAVID A. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON, P.C.
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

JOHN V. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

TINA THOMAS
REMY, THOMAS, MOOSE AND MANLEY LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

[illegible]EN M. TEICHERT
CITY ATTORNEY

ALFRED F. JAHNS
LAW OFFICE ALFRED F. JAHNS

CITY OF SACRAMENTO
915 I STREET, ROOM 4010
MENTO, CA 95814-2604
TY OF SACRAMENTO

3436 AMERICAN RIVER DRIVE, SUITE 12
SACRAMENTO, CA 96864
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

Information Only

KARI KLOBERDANZ
REGULATORY CASE ADMINISTRATOR
SOUTHERN CALIFORNIA GAS COMPANY
555 WEST 5TH STREET, GT14D6
LOS ANGELES, CA 90013-1011
FOR: SOUTHERN CALIFORNIA GAS COMPANY

MARCIE MILNER
DIRECTOR - REGULATORY AFFAIRS
SHELL TRADING GAS & POWER COMPANY
4445 EASTGATE MALL, SUITE 100
SAN DIEGO, CA 92121

JOHN W. LESLIE
ATTORNEY AT LAW
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
11988 EL CAMINO REAL, SUITE 200
SAN DIEGO, CA 92130

KATARZYNA M. SMOLEN
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B9A
SAN FRANCISCO, CA 94105

PAUL C. LACOURCIERE
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO, CA 94105

PETER V. ALLEN
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO, CA 94105-3606

JEANNE B. DAY
GOODIN,MACBRIDE,SQUERI,DAY&LAMPREY,LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE, LLC

MICHAEL B. DAY
ATTORNEY AT LAW
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

EDWARD O'NEILL
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
FOR: DAVIS WRIGHT TREMAINE LLP

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST. SUITE 303
SAN FRANCISCO, CA 94117

KERRY C. KLEIN
ATTORNEY AT LAW
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120
FOR: PACIFIC GAS AND ELECTRIC COMPANY

MRW AND ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND, CA 94612
FOR: MRW AND ASSOCIATES, INC.

ROCHELLE AMRHEIN
CITY OF SACTO, ENVIRONMENTAL PLANNING SV
300 RICHARDS BOULEVARD, 3RD FL
SACRAMENTO, CA 95811

ASHLE CROCKER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

CHRIS BUTCHER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

COLIN BAILEY
LEGAL SERVICES OF NORTHERN CALIFORNIA
515 12TH STREET
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

R. ROPELATO
SERVICES OF NORTHERN CALIFORNIA
5.. 12TH STREET
SACRAMENTO, CA 95814

MICHAEL T. SPARKS
SENIOR DEPUTY CITY ATTORNEY
CITY OF SACRAMENTO
915 I STREET, ROOM 4010

D2-296
(Cont.)

FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.

MA: A G. JACOBS
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428
FOR: AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION

THOMAS ENSLOW
ADAMS BROADWELL JOSEPH & CARDOZO
520 CAPITOL MALL, SUITE 350
SACRAMENTO, CA 95814-4715
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

RONALD LIEBERT
ATTORNEY AT LAW
CALIFORNIA FARM BUREAU FEDERATION
2300 RIVER PLAZA DRIVE
SACRAMENTO, CA 95833

ANN L. TROWBRIDGE
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DRIVE, SUITE 205
SACRAMENTO, CA 95864

SACRAMENTO, CA 95814-2604
FOR: CITY OF SACRAMENTO

SCOTT W. PINK
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428
FOR: AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION

SLIDER CONSTANCE
CO-CHAIR
AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.
5740 WILKINSON STREET
SACRAMENTO, CA 95824
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSOCIATION (AGENA)

STEVEN M. COHN
ASSISTANT GENERAL COUNSEL
SACRAMENTO MUNICIPAL UTILITY DISTRICT
PO BOX 15830
SACRAMENTO, CA 95852-1830

State Service

EUGENE CADENASSO
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

PAUL S. PHILLIPS
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5306
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RICHARD SMITH
CALIF PUBLIC UTILITIES COMMISSION
DIVISION OF ADMINISTRATIVE LAW JUDGES
ROOM 5007
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

JAMES W. REEDE JR., ED.D.
ENVIRONMENTAL SCIENCE PROFESSOR
1516 - 9TH STREET
SACRAMENTO, CA 95814

MICHAEL ROSAUER
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RICHARD A. MYERS
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: ENERGY DIVISION

ROBERT MASON
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5141
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

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(Cont.)

APPENDIX 22

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application by Sacramento Natural Gas Storage, LLC for a Certificate of Public Convenience and Necessity for Construction and Operation of Natural Gas Storage Facilities and Requests for Related Determinations	Application No. 07-04-013 (filed April 9, 2007)

REPLY TESTIMONY OF

ROBERT MANNON

ON BEHALF OF

SACRAMENTO NATURAL GAS STORAGE, LLC

ALFRED F. JAHNS
Law Office of Alfred F. Jahns
3436 American River Drive, Suite 12
Sacramento, CA 95864
Telephone: (916) 483-5000
Facsimile: (916) 483-5002
E-mail: ajahns@jahnsatlaw.com

JOHN V. DIEPENBROCK
DAVID A. DIEPENBROCK
Diepenbrock Harrison
400 Capitol Mall, Suite 1800
Sacramento, CA 95814
Telephone: (916) 492-5000
Facsimile: (916) 446-4525
E-mail: jdiepenbrock@diepenbrock.com
E-mail: ddiepenbrock@diepenbrock.com

Dated: October 3, 2008

Q1 ***Please State Your Name, Address And Occupation.***

Robert W. Mannon
1045 Via Tranquila
Santa Barbara, CA 93110
President, Mannon Associates, Inc.

Q2 ***Please State Your Education, Degrees.***

B.S. Petroleum Engineering, Stanford University
M.S. Petroleum Engineering, University of Southern California
PhD Petroleum Engineering, University of Southern California

Q3 ***Please State Your Work Experience***

I have over fifty years of experience worldwide in the oil and gas industry divided almost equally between employment with major and independent oil and gas companies and consulting and teaching. My specialties are production and reservoir engineering, enhanced oil recovery, and oil and gas reserve estimation and economic analysis.

I have been employed by: the Southern California Petroleum Corp. as a Drilling and Production Engineer in California, New Mexico, Texas, and Egypt; Gulf Oil Corp. in California as a Reservoir Engineer; Buttes Gas and Oil as Division Engineer International; Allied Chemical Company's Petroleum Division as Manager, Drilling and Production International; and Ogle Petroleum Inc. as Vice President of the company's consulting services for California onshore and offshore operations.

I have also taught petroleum engineering at the University of Southern California, the Montana College of Mineral Science and Technology, and the University of Louisiana-Lafayette where he served as department head. I earned a B.S. in Petroleum Engineering from Stanford University, and M.S. and Ph.D. degrees in Petroleum Engineering from the University of Southern California. I was a recipient of National Science Foundation and Baker Oil Tool fellowships while pursuing his graduate studies at the University of Southern California.

I am a member of the Society of Petroleum (SPE) and a Legion of Honor member of SPE. I am also a member of the Society of Petroleum Evaluation Engineers (SPEE), the American Association of Petroleum Geologists (AAPG), and the National Panel of Arbitrators of the American Arbitration Association (AAA). I am past chairman of the Los Angeles Petroleum Forum of SPE and am a Registered Petroleum Engineer in California.

In October 1983, I founded Mannon Associates, Inc to specialize in petroleum and natural gas reservoir engineering, oil and gas reserve estimation and economic analysis, enhanced oil recovery, and offshore project analysis. Since its founding, Mannon Associates has been involved in numerous large scale and smaller scale projects in California. Listed below is a partial list of major consulting assignments in California oil and gas fields.

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- Consultant to Texaco Harvest Partners – Point Arguello Field, Offshore California
- Consultant to Torch Energy Advisors – Point Pedernales Field, Offshore California
- Consultant to Chevron USA for the Stevens Reservoirs, Elk Hills Field, Kern County California
- Consultant to California independent oil company concerning Chevron USA interest in the Hondo A Field, offshore California
- Testimony before California Public Utilities Commission for Southern California Edison Company concerning sale of interests in gas properties
- Estimation of Proved Developed and Proved Undeveloped oil and gas reserves and economic analysis for interest owners in the Pt. Pedernales, Gato Canyon, Lion Rock, Purisima Pt., Pt. Sal, Bonito, Cavern Pt., Sword, Sacate, and Pescado Federal OCS Units, Offshore California
- Testimony before the U.S. Department of Justice for Texaco, Inc. related to heavy oil properties in California
- Consultant to Aera Energy on Santa Maria Basin Federal Units, Offshore California
- Consultant to Dames and Moore for the California Offshore Oil and Gas Energy (COOGER) Study
- Consultant to Samedan Oil Corp. on Monterey pool performance
- Monterey Reservoir Study Project of selected Monterey pools in California for major oil company consortium
- Study of the performance of the South Elwood & Casmalia heavy oil pools in California for independent oil companies
- Testimony in U.S. Federal Court re: Home-Stake Production Co. securities litigation
- In-depth studies of performance of Potter Sand and Monarch reservoirs in the Midway-Sunset Field for a major oil company and an independent oil company
- An in-depth study of reservoir performance in the North and South Belridge Fields for a major company
- An in-depth study of reservoir performance in the Monarch Sand of the Central Midway-Sunset field for a large independent company
- Reservoir study of the Oxnard field for a major company

D2-297 (Cont.)

- Testimony in U.S. Federal Court, Bureau of Land Appeals on behalf of Aera Energy, LLC
- Testimony in U.S. Court of Appeals on behalf of Delta Petroleum Corp.

Q4 ***Are You Familiar With The Florin Field Natural Gas Reservoir Located In Southern Sacramento?***

Yes. I prepared a report for Sacramento Natural Gas Storage, LLC regarding the proposed project, which I understand was submitted to the California Public Utilities Commission in connection with its environmental review of the proposed project.

Q5 ***Are You An Editor of The Book Entitled "Oil And Gas Production From Carbonate Rocks," published in 1972?***

Yes.

Q6 ***Does Your Book Include Information On Oil Recovery Factors For Solution Gas Drive Oil Reservoirs And Gas Cap Drive Oil Reservoirs On Pages 365 And 377 Where The Oil Recovery Factor Is Defined As The Actual Or Estimated Ultimate Oil Recovery From A Given Oil Reservoir As A Percentage Of The Original Oil In Place For That Reservoir?***

Yes.

Q7 ***Are True And Correct Copies of Those Pages Attached As Exhibit A?***

Yes.

Q8 ***Do Those Pages State That The Oil Recovery Factors For Solution Gas Drive Oil Reservoirs Range From 14-40 Percent And A Corresponding 20-30 Percent For Gas Cap Drive Oil Reservoirs?***

Yes.

Q9 ***Please Explain The Meaning of "Recovery Factor" As Used In Your Book.***

The recovery factor represents the estimated or actual ultimate oil recovery from an oil reservoir as a percentage of the original oil in place.

Is The Florin Field A Solution Gas Drive Oil Reservoir?

No.

Q10 ***Is The Florin Field A Gas Cap Drive Oil Reservoir?***

No.

D2-297
(Cont.)

Q11 ***What Type Of Reservoir Is The Florin Field Reservoir?***

The Florin Field is a dry gas reservoir with a partial water drive.

Q12 ***Does Your Book Include Information On Recovery Factors for Natural Gas Reservoirs Such As The Florin Field?***

No. That book has no application to gas reservoirs like the Florin Field that contain no oil; it applies only to production from oil reservoirs, or reservoirs that contain both oil and gas.

Q13 ***Does The Florin Field Include Any Carbonate Rock Formations?***

No.

Q14 ***Is Information Establishing That The Florin Field Contains No Carbonate Rock Formations Publicly Available?***

Yes. Publications by the California Division of Oil, Gas, and Geothermal Resources clearly indicate that geologic formations in the Florin Field consist entirely of sandstones and shales and are devoid of carbonates.

Q15 ***In Your Opinion, Should A Petroleum Engineer Licensed With The State Of California Know That Your 1972 Book Would Not Provide Recovery Factors For The Florin Field?***

Q16 Yes. In fact, graduates from a petroleum engineering program at any accredited college or university in this state would know that my book does not provide recovery factors for gas reservoirs like the Florin Field.

Q17 ***Would You Expect A Petroleum Engineer Licensed With The State Of California To Be Able To Determine Whether The Florin Field Contained Oil?***

Yes. That information is readily available on the website maintained by the California Department of Oil, Gas, and Geothermal Resources.

Q18 ***In Your Experience, Is It Reasonable To Achieve A Recovery Factor Of 63 Percent From A Reservoir Such As Sacramento's Florin Field?***

Yes, it is.

Q19 ***Does That Conclude Your Reply Testimony?***

Yes.

D2-297 (Cont.)

EXHIBIT A

Oil and Gas Production FROM Carbonate Rocks

EDITED BY

George V. Chilingar
Robert W. Mannon
Herman H. Rieke, III

Elsevier
New York · London · Amsterdam



D2-298

Oil and gas column (ft)	Pay thickness (ft)	Crude gravity (°API)	ϕ (%)	k (md)	S_{wi} (%)	P_i (psi)	P_b (psi)	T (°F)	Solution GOR (cu ft/bbl)	Ultimate recovery (MMbbl)	(%)	Ref. No.
50–60	140	30–41.5								5[c]		1
	400	30	9.4	16.2		2,040				39[c]		2
350	185	46	15	1	37	4,145	2,764	139	1,300	69	25[i]	3
27	11	37										1
25	5	35.8		-		600						1
20	14	34.4			44	1,330						1
235	42	47	4–5	35	35–45	2,230	2,230	134	975	26	28[i]	4
	200	36.4	8	1	35	158–1,760	1,140	96	371		13.6	5
330	216		7.7–11.4	6.7–12.6	24	2,980	2,370		1,590	246	26.5	6
	6–12	38	8–12	100		800–1,200				0.9[c]		7
		36	11.3	113		3,636	3,636	203	871	45–60	30–40[i]	8
	11.3	38–40	19–20	23	23	2,440	2,331	179	460	14.9 28.5[k]	18 34[k]	9
10	3–4	29–40										1
100–125	8–65	43.5	15	16		4,246				13[l]	42.5	2
550		32	13	20	30	1,300	755	86	315			10
	11	43	18.9	379	25.4	3,425	907	203	256	8.1	19	11
	60	40–46	12	25	30–45	440	440	85	275	1,200[f]		12–14
215	21	45.5	6.8	2.6	33	4,567	3,508	174	1,817	3.9	17	15
220	8	50	20	250	25	3,578	3,578	209	1,915	6.6[g]	19.4	16
60	20	38.5				375				4.0[j]		7
60	40	34	13.2	4.6								2
	40	29–32	12.2	10	11	1,710	1,710	108	465	275[c]	20	17–19
	40	34.8	7.5	24	31	1,760	325	96	160	10.4		20
80		0.7[b]	28.1	43	22	1,003	253	136	90–100	75[f]		21
280	150	34	11.8	12.3	35.5	1,650	1,134	88	484	33[c]	21	22
	8	35	9–21	1–49		2,550			395	1.4	14	23

D2-298 (Cont.)

	Field name	State, country	County	Exploration discovery method	Productive formation	Geologic age	Trap mechanism	Reservoir rock type	Productive acreage (acres)
AB: Vugular-solution porosity—solution gas drive									
25	Aneth	Utah	San Juan		Paradox	P	4–5	L	55,000
26	Bar-Mar	Texas	Crane	SG	Tubb	D	2–5	D	80
27	Bateman Ranch	Texas	King	G	Strawn B-Zone	P	1	L	1,700
	Bateman Ranch	Texas	King	G	Strawn C-Zone	P	1	L	1,450
28	Big Eddy	New Mexico	Eddy	GS	Strawn	P	4	L	640
29	Fairway*	Texas	Henderson	SG	James Lime	K	4	L	23,000
30	GMK	Texas	Gaines	SGS	San Andres	P	1	D	1,280
31	Golden Spike South, D-3A	Alberta, Canada			Leduc	D	4	L	1,390
32	Kelly-Snyder	Texas	Scurry	SGS	Canyon Reef	P	4	L	51,000
33	Morrow County	Ohio	Morrow		Trempealeau	C	1	D	
34	North Anderson Ranch	New Mexico	Lea	GS	Wolfcamp	P	1	L	920
35	Nunn	Kansas	Finney	S	Marmaton	P	1	L	1,100
36	Plainville	Indiana	Daviess	S	Aux Vases	M	1	D	400
37	Pleasant Prairie	Kansas	Haskell	W	Morrow	P	5	L	10,000
38	Pollnow	Kansas	Decatur	S	Lansing—Kansas City	P	5	L	800
39	Sharon-Ridge	Texas	Scurry		Canyon Reef	P	4	L	11,000
40	Sun City	Kansas	Barber	G	Marmaton	P	5	L	300
41	Sycamore-Millstone	West Virginia	Calhoun	W	Greenbrier	M	8	D	6,000

* Considerable gas-cap drive. ** Includes No. 208. *** Includes No. 18. **** Plus 10.95 MMbbl owing to water injection; estimated ultimate recovery under water injection is over 50%.

AC: Fracture-matrix porosity—solution gas drive									
42	Bitter Lake South and West	New Mexico	Chaves		San Andres	P	1–7	D	680
43	Brown	Texas	Gaines	SGS	Glorieta	P	6	D	960
44	Cottonwood Creek	Wyoming	Washakie	S	Phosphoria	P	5–6	D	14,200
45	Devil's Basin	Montana	Musselshell	G	Van Duzen	M	1	L	80
46	Elk Basin	Montana, Wyoming	Park-Carbon		Madison A Zone	M	1	D	8,960
47	Reeves	Texas	Yoakum	S	San Andres	P	5	D-L	5,480
48	Yellow House	Texas	Hockley	S	San Andres	P	6	D	3,230

D2-298 (Cont.)

Oil and gas column (ft)	Pay thickness (ft)	Crude gravity (°API)	ϕ (%)	k (md)	S_{wi} (%)	p_i (psi)	p_b (psi)	T (°F)	Solution GOR (cu ft/bbl)	Ultimate recovery (MMbbl)	(%)	Ref. No.
		27				1,055				0.12[c]		44
67	113	39	7	23.1	20	5,051		157			35	2
	0–113	34–35										36
175	15	37	7–11			5,180				3.36		2
30	6	41.1										31
36	14	Gas	16	61		1,105						1
	20	52				4,035						41
	15.3	42								2.0[c]		1
	20	44	11–17	59		3,400	3,400		1,400		20–30	41, 47
[illegible]	28	Gas				550				3.4 × 10[8] Mcf		7
		Gas										36
	12	Gas										36
1,068	162	53.4	8.1	10	20	5,937				5.6 × 10[8] Mcf[c]		2
	14	Gas	20	54		119				3 Bcf		7
20	4	38	7.8–14.6	0.8–4,240	44.3–75.9	1,280				0.8[c]		36
500	135	Gas	6.7	1–100	35	6,648				1.5 × 10[8] Mcf[c]		2
1,715	790	51.2[d]	1.33	0.56	10	6,964				4.3 × 10[8] Mcf[c]		2
580	140	56[d]	12	1		3,000				1.0–3 × 10[9] Mcf		2
	65	Gas				435				10[8] Mcf		1
	40	44	10		27	3,250						2
	361	49.4	14	0–27.9	25	5,890			21,000	0.8[c]		45
181	180	49.5[d]								1.9 × 10[8] Mcf[c]		2
1,600	1,030	53[d]								7.9 × 10[8] Mcf[c]		2

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(Cont.)

	Field name	State, country	County	Exploration discovery method	Productive formation	Geologic age	Trap mechanism	Reservoir rock type	Productive acreage (acres)
D: Open Combination Drive									
DA: Intercrystalline-intergranular porosity—open combination drive									
188	Abqaiq	Saudi Arabia			Arab D	J	1	L	89,300
189	Adell Northwest	Kansas	Decatur	W	Lansing—Kansas City	P	1	L	320
190	Aden Consolidated and Aden South	Illinois	Wayne, Hamilton	S	Ohara	M	1	L	2,700
	Aden Consolidated and Aden South	Illinois	Wayne, Hamilton	S	Rosiclare	M	1	L	2,700
	Aden Consolidated and Aden South	Illinois	Wayne, Hamilton	S	McClosky	M	1	L	2,700
	Aden Consolidated and Aden South	Illinois	Wayne, Hamilton	S	Salem	M	1	L	2,700
	Aden Consolidated and Aden South	Illinois	Wayne, Hamilton	S	Warsaw	M	1	L	2,700
191	Bahrain	Bahrain			Second Pay	K	1	L	
192	Dale Consolidated	Illinois	Hamilton, Saline	S	Ohara	M	1	L	20,000
	Dale Consolidated	Illinois	Hamilton, Saline	S	Rosiclare	M	1	L	20,000
	Dale Consolidated	Illinois	Hamilton Saline	S	McClosky	M	1	L	20,000
193	Damme	Kansas	Finney	SG	Marmaton	P	1	L	
194	Feely	Kansas	Decatur	W	Lansing	P	5	L	160
195	Ghwar-Ain-Dar	Saudi Arabia			Arab D	J	1	L-D	4,000
196	Ghwar-Fazran	Saudi Arabia			Arab D	J	1	L-D	136,500
197	Ghwar-Harab	Saudi Arabia			Arab D	J	1	L-D	110,100
198	Ghwar-Hawiyan	Saudi Arabia			Arab D	J	1	L-D	298,600
199	Ghwar-Shedgum	Saudi Arabia			Arab D	J	1	L-D	4,100
200	Ghwar-Uthmaniyan	Saudi Arabia			Arab D	J	1	L-D	47,400
201	Howard Glasscock	Texas	Howard, Glasscock, Sterling, Mitchell	G	San Andres Grayburg	P	1	D	15,620
202	Jingo	Kentucky	Ohio	SG	Salem	M	5	L	90
203	Pleasant Prairie	Kansas	Finney, Kearney, Haskell	W	Lansing—Kansas City	P	5	L	
	Pleasant Prairie	Kansas	Finney, Kearney, Haskell	W	St. Louis	M	1-5	L	10,000

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served by electronic mail to each person listed on the attached service list, in accordance with Rules 1.9, and 1.10 of the Commission's Rules of Practice and Procedure, the **REPLY TESTIMONY OF ROBERT MANNON** submitted on behalf of Sacramento Natural Gas Storage, LLC.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Dated: October 3, 2008, at Sacramento, California.

/s/
Sandra J. Andrade

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(Cont.)

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ties

PETER G. ESPOSITO
CRESTED BUTTE CATALYSTS, LLC
PO BOX 668
CRESTED BUTTE, CO 81224
FOR: LODI GAS STORAGE

JONATHAN BROMSON
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
ROOM 4107
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: DRA

JEANNE B. ARMSTRONG
ATTORNEY AT LAW
GOODIN MACBRIDE SQUERI DAY & LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

LAW DEPARTMENT
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120-7442
FOR: PACIFIC GAS AND ELECTRIC COMPANY

DAN L. CARROLL
ATTORNEY AT LAW
DOWNEY BRAND, LLP
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO, CA 95814
FOR: LODI GAS STORAGE

DAVID A. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON, P.C.
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

JOHN V. DIEPENBROCK
ATTORNEY AT LAW
DIEPENBROCK HARRISON
400 CAPITOL MALL, SUITE 1800
SACRAMENTO, CA 95814
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

TINA THOMAS
REMY, THOMAS, MOOSE AND MANLEY LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

[illegible] M. TEICHERT
CITY ATTORNEY

ALFRED F. JAHNS
LAW OFFICE ALFRED F. JAHNS

D2-298
(Cont.)

CITY OF SACRAMENTO
915 I STREET, ROOM 4010
SACRAMENTO, CA 95814-2604
CITY OF SACRAMENTO

3436 AMERICAN RIVER DRIVE, SUITE 12
SACRAMENTO, CA 96864
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

Information Only

KARI KLOBERDANZ
REGULATORY CASE ADMINISTRATOR
SOUTHERN CALIFORNIA GAS COMPANY
555 WEST 5TH STREET, GT14D6
LOS ANGELES, CA 90013-1011
FOR: SOUTHERN CALIFORNIA GAS COMPANY

MARCIE MILNER
DIRECTOR - REGULATORY AFFAIRS
SHELL TRADING GAS & POWER COMPANY
4445 EASTGATE MALL, SUITE 100
SAN DIEGO, CA 92121

JOHN W. LESLIE
ATTORNEY AT LAW
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
11988 EL CAMINO REAL, SUITE 200
SAN DIEGO, CA 92130

KATARZYNA M. SMOLEN
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B9A
SAN FRANCISCO, CA 94105

PAUL C. LACOURCIERE
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO, CA 94105

PETER V. ALLEN
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO, CA 94105-3606

JEANNE B. DAY
GOODIN,MACBRIDE,SQUERI,DAY&LAMPREY,LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE, LLC

MICHAEL B. DAY
ATTORNEY AT LAW
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
FOR: WILD GOOSE STORAGE

EDWARD O'NEILL
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
FOR: DAVIS WRIGHT TREMAINE LLP

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST. SUITE 303
SAN FRANCISCO, CA 94117

KERRY C. KLEIN
ATTORNEY AT LAW
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120
FOR: PACIFIC GAS AND ELECTRIC COMPANY

MRW AND ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND, CA 94612
FOR: MRW AND ASSOCIATES, INC.

ROCHELLE AMRHEIN
CITY OF SACTO, ENVIRONMENTAL PLANNING SV
300 RICHARDS BOULEVARD, 3RD FL
SACRAMENTO, CA 95811

ASHLE CROCKER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

CHRIS BUTCHER
REMY, THOMAS, MOOSE AND MANLEY, LLP
455 CAPITOL MALL, SUITE 210
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

COLIN BAILEY
LEGAL SERVICES OF NORTHERN CALIFORNIA
515 12TH STREET
SACRAMENTO, CA 95814
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN. (AGENA)

S[illegible]. ROPELATO
SERVICES OF NORTHERN CALIFORNIA
5[illegible] 12TH STREET
SACRAMENTO, CA 95814

MICHAEL T. SPARKS
SENIOR DEPUTY CITY ATTORNEY
CITY OF SACRAMENTO
915 I STREET, ROOM 4010

D2-298
(Cont.)

FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.

MA: W G. JACOBS
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428
FOR: AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION

THOMAS ENSLOW
ADAMS BROADWELL JOSEPH & CARDOZO
520 CAPITOL MALL, SUITE 350
SACRAMENTO, CA 95814-4715
FOR: SACRAMENTO NATURAL GAS STORAGE, LLC

RONALD LIEBERT
ATTORNEY AT LAW
CALIFORNIA FARM BUREAU FEDERATION
2300 RIVER PLAZA DRIVE
SACRAMENTO, CA 95833

ANN L. TROWBRIDGE
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DRIVE, SUITE 205
SACRAMENTO, CA 95864

SACRAMENTO, CA 95814-2604
FOR: CITY OF SACRAMENTO

SCOTT W. PINK
DLA PIPER US LLP
400 CAPITOL MALL, SUITE 2400
SACRAMENTO, CA 95814-4428
FOR: AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION

SLIDER CONSTANCE
CO-CHAIR
AVONDALE GLEN-ELDER NEIGHBORHOOD ASSN.
5740 WILKINSON STREET
SACRAMENTO, CA 95824
FOR: AVONDALE GLEN-ELDER NEIGHBORHOOD ASSOCIATION (AGENA)

STEVEN M. COHN
ASSISTANT GENERAL COUNSEL
SACRAMENTO MUNICIPAL UTILITY DISTRICT
PO BOX 15830
SACRAMENTO, CA 95852-1830

State Service

EUGENE CADENASSO
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

PAUL S. PHILLIPS
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5306
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RICHARD SMITH
CALIF PUBLIC UTILITIES COMMISSION
DIVISION OF ADMINISTRATIVE LAW JUDGES
ROOM 5007
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

JAMES W. REEDE JR., ED.D.
ENVIRONMENTAL SCIENCE PROFESSOR
1516 - 9TH STREET
SACRAMENTO, CA 95814

MICHAEL ROSAUER
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

RICHARD A. MYERS
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
AREA 4-A
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
FOR: ENERGY DIVISION

ROBERT MASON
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
ROOM 5141
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214

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(Cont.)

APPENDIX 23

Economic Analysis of Alternative Fields

Snodgrass Slough, Freeport & Thornton vis a vis Florin

INTRODUCTION

The Snodgrass Slough Gas Field, the Thornton Gas Field and the Freeport Gas Field have been identified in the Draft EIR as potential alternatives to the Florin Field for development as a gas storage project serving the Sacramento area and particularly SMUD. In the Executive Summary to the Draft EIR (page ES-9) the CEQA Guidelines definition of an "alternative" is quoted as follows:

> . . .capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors.

The Draft EIR concludes that the three above-mentioned projects are potential alternatives to the SNGS Project, even though the Draft EIR recognizes as to each such alternative that "given the relative low returns on investment, it is doubtful that the alternative would be financially feasible." (Draft EIR at p. ES-21.) The following analysis demonstrates that the financial feasibility of each such alternative is worse than "doubtful," it is impossible.

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The following economic analyses have been prepared utilizing carefully-researched SNGS unit costs with adjustments to reflect their individual characteristics. These adjustments are explained in the description of each field. In the case of Thornton, two models have been prepared: one that is comparative to the scale of the proposed SNGS Project; and a second that is a complete build-out of this large field.

THE MODEL

The model is presented in an identical budget format for each field and a financial summary is included for each field as well. Cost factors included in the budget for each project component are: Well Construction, Pipelines, Compression and Construction, Pad Gas[1] requirement, Land or right-of-way acquisition, Engineering and Permitting, General Project Overhead, Contingency, Start-up cost, and Financing cost.

To qualify as a true potential alternative, a field must provide for 100 thousand Mcf a day of injection and 200 thousand Mcf a day of withdrawal, and 7 to 9 Bcf of working gas storage capacity. These specifications will entail a 3 turn service[2] per year of the storage facility and are

[1] Pad Gas is the gas that must be in the field to establish a reasonable pressure for storage operations. This is normally about ¼ to 1/3 of the initial gas in place in the field.

[2] A turn represents the time that it takes to inject and withdraw gas from the field. Historically, a typical service is a summer/winter program where gas is injected into the field in the summer and withdrawn in the winter; that is a 1 turn service. In this time of independent procurement and management of gas, a multi-turn service is needed to make daily changes in storage volumes to keep gas supply balanced on the pipeline systems, adjust for workload requirements and, take advantage of daily pricing changes in the marketplace.

within the constraints of the SMUD Pipeline for the delivery of gas to and from the field. The SMUD Pipeline is the only access from the PG&E Backbone system into the Sacramento Region that has excess capacity for the transport of the storage gas.

Well Construction

It is assumed that each injection/withdrawal[3] well will provide about 20 million ± cubic feet a day of injection and 40 million ± cubic feet per day of withdrawal (the same rate as was used for the SNGS, LLC project). In order to provide the requisite volumes for a 3 turn service, this will typically require 5 wells. Throughout this model, this number has been utilized except for adjustments to the capacity of the fields.

It is also assumed that each field will require 1 monitoring well[4] and 1 water injection well[5].

Cost Assumptions:

- Set up of the rig and the drilling of the first 3000 feet of an injection/withdrawal well will be $1,000,000 per well for the first 3000 feet of drilling for Injection/Withdrawal wells. Each 1000 feet thereafter will be an additional $100,000.[6]

- Each monitoring well will cost $700,000 for the first 3000 feet and $100,000 for each additional 100,000 feet.

- Each water disposal well will cost $800,000 for the first 3000 feet and $100,000 per thousand feet thereafter.

The costs are based on utilizing a 7 5/8" casing in all Injection/Withdrawal wells and a smaller casing in monitoring and water disposal wells. This also includes automatic shut off equipment, water separation equipment, tanks and pumps. Other operating and communication equipment at the well site is included in the Construction budget.

Pipelines

For the volumes of gas that needs to be moved in to and out from the project, a 16" Class 3 Federal DOT Standard pipeline will suffice. The pressure between the SMUD pipeline and the compressor station will be 600 Psi ±. The pressure between the compressors and the wells will vary depending on the field and the depth of the production zone. For the Thornton Field, the

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[3] An injection/withdrawal well is a single well that both provides for the movement of gas into the formation in the field as well as the withdrawal of gas from the field.

[4] A monitoring well is a well that is drilled to monitor changes of pressure/temperature and other factors within the field and above the cap rock.

[5] A water injection well is a well that is utilized for injecting water that is produced with the gas on withdrawal, back into the zone from which it was originally produced.

[6] The drilling numbers are estimates but have been validated as reasonable by Sahid Irani, Reservoir Engineer. Irani Engineering is the principal drilling engineering company in Northern California, and is expected to drill the Florin wells.

pressure will be 1600 ± to 1700 Psi maximum. For Snodgrass and Freeport Fields the pressure will need to be 3000 ± to 3200 Psi. The pipeline cost is estimated at $1,500,000 per mile [7].

Other than Freeport, all alternatives will have significant pipeline drills under streams and roads and all will have an interconnecting meter station. The meter station will include a 2 way meter, a chromatograph for measuring gas quality and equipment for controlling pressure. Each will include 2 way communication equipment for real time monitoring from the central control site. Each meter station will cost about $1,000,000 [8].

Compression/Construction

Two 3500 Hp compressors will compress 100 MMcf of gas per day from 600 ± Psi to 1700 ± Psi. This is done in tandem (2 stages). It will take three or four stages to raise the pressure to 3000 ± Psi, the amount required for the Snodgrass or Freeport Fields because of the increased depth of the fields which involve significantly higher pressure. For purposes of the analysis, 3 compressors have been included for Snodgrass and Freeport (probably one too few).

Other components of the compressor station include a dehydration system that is used to dry the gas. It will also include equipment for enrichment to assure that the gas delivered is of appropriate quality for the pipeline.[9] A building will be constructed for the central control function of the total project and staff will monitor all operations 24 hours a day. There will be a generator for back-up electricity and a building for electrical and electronic operations.

The Construction component includes the construction of the compressor station and the surface equipment at the well site(s). Well drilling and well equipment costs are listed under the well budget and the construction cost of the pipeline is listed under the pipeline budget.

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Pad Gas

All three alternative fields will require the addition of pad gas before the start of operations to repressure the field. (See footnote 1)

[7] Cost estimate by ARB, the expected SNGS pipeline contractor.
[8] Cost estimate by ARB, the expected SNGS pipeline contractor.
[9] SMUD will require the same quality of gas as the PG&E tariff. This limits the amount of Nitrogen and other impurities. It requires a Btu rating of about 990 to 1020.

Land Acquisition

A review of the DOGGR[10] maps indicates that the overlying acreage of the three alternate fields is approximately:

- Freeport 600 – 700 acres
- Snodgrass Slough 500 – 600 acres
- Thornton 6000 – 7000 acres

Note: Does this use of DOGGR map sizes undercut our position vs. the DEIR regarding the Florin size disparity?

The Freeport field is overlaid by the Sacramento waste water plant. The Snodgrass Slough field is overlaid by farms and marsh. There are many acres of grapes in the area. Finally, Thornton is overlaid by Nature Conservancy property and vineyards.

At Freeport, some 6 acres would be required for the compressor station and a well site plus 3 acres for a well site at another location at the south edge of the field.

At Snodgrass Slough, some 6 acres would also be required for the compressor station and a well site of about 6 acres and plus a second well site of some 3 acres.

Finally, at Thornton, some 6 acres would also be required for the compressor station and well site plus two additional well sites of about 3 acres each.

It is estimated that the land for these three rural properties would sell for about $100,000 per acre[11] (or considerably more contingent upon the vineyards on the surface). Land for the Florin project cost $1,200,000 for four acres for a well site.

Note: $100,000/acre seems very high for farmland, even all vines. Suggest you ask Irv Rios.

Cost of right-of-way for pipelines is included in the pipelines estimate.

Engineering and Permitting, Etc.

This includes all of the Engineers, Consultants, Attorneys, and other related costs requisite to obtaining a CPCN from the Public Utilities Commission as well as local permits from the cities and counties and permits from the Corps of Engineers, Fish and Game, Water resources ad. Infinitum.

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[10] DOGGR is the California Division of Oil Gas And Geothermal Resources. It was created in about 1917 to oversee all oil and gas drilling and production activities and a main rationale was/is the protection of the fresh water table. DOGGR keeps records on all oil and gas wells in California including well logs, well histories, production data, etc. The maps utilized do not define the reservoir but rather a general area under which it is assumed the reservoir lays.

[11] The compressor station (5 acres) is under lease from Depot Park (a closed army depot).

Contingency

At such an early stage of cost projecting this would typically approach 20%. However, we have elected to be conservative and have assigned a 10% contingency to all of the preceding activities.

Start up Cost

This includes the cost of parts for the warehouse, tools, testing, and a myriad of other activities such as shake-down of computer systems, integration with PG&E and SMUD, etc.

FIELD DATA

Snodgrass Slough

Gas Originally Produced	4.8 Bcf
Pad Gas required	1.6 Bcf
Storage capacity	3.2 Bcf

Note: The DEIR carries this at "greater than 2 Bcf" (ES 13) which is much better for us. Can we not use the DEIR capacity or at least show the DEIR as a footnote to show how conservative our approach is?

Quality of gas[12]	849 Btu
Depth of field[13]	8000 subsea
Compressors required[14]	3 - 4
Original Pressure	3200 Psi
Ending Pressure	not recorded
Wells drilled	7
Dry holes	3
Drive	Depletion

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[12] Taken from the completion history of Esperanza 10-1 (12-13-95)
[13] The depth of wells is measured below sea level. Actually, all of the fields included herein are probably less than 25 feet above sea level.
[14] The compressors for each field are assumed to be about 2,500 Hp each.

Freeport

Gas Originally Produced	2.8 Bcf
Pad Gas required	.9 Bcf
Storage capacity	1.9 Bcf

Note: The DEIR carries this as "over 1 Bcf." Same question as Snodgrass.

Quality of gas	609 Btu
Depth of field	5800 subsea
Compressors required	3 +
Original Pressure	3000 Psi
Ending Pressure	2510
Wells drilled	12
Dry holes	9
Drive	Depletion

Thornton

Gas Originally Produced	54 Bcf
Pad Gas required	18 Bcf
Storage Capacity	36 Bcf
Quality of gas	960 Btu
Depth of field	3200 subsea
Compressors required	2 +
Original Pressure	1500 Psi
Ending Pressure	650 Psi
Wells drilled	37
Dry holes	22
Drive	water/depletion

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(Cont.)

Comments on Fields and Budget

Criteria for Field Selection

There are a number of preliminary screening criteria for the selection of a field for storage. These include geologic, engineering and economic considerations, including:

- Depth of field. As the depth increases, pressures increase and the potential problems during operation likewise escalate. This increases costs of operation significantly. A typical guideline is to stay within a mile of the surface.

- Size of field. The field should be large enough to be economically viable and small enough so that the cost of pad gas does not swamp the project. Typically this should be a field that produced about 8 to 25 Bcf of gas. Considering that in a depletion drive field (all three of the alternative fields are this type) that about 1/3 of the produced gas needs to be replaced for "pad" gas to repressurize the field, this provides a working gas volume of about 5 to 17 Bcf.

- SMUD requirements. SMUD needs 4 Bcf, a capacity conceded by SMUD representatives to be less than the ideal capacity.

- Type of drive. A water drive field is preferable to a depletion drive as the water pressure contributes to the maintenance of pressure thus reducing the need for suction; i.e., reverse compression on withdrawals of gas. Typically, a water drive requires less pad gas then a depletion drive.

- Quality of gas. Gas received into storage from commercial pipelines has a Btu rating of about 1,000 Btu. Residual gas in the field will mix with the storage gas and the resultant is a blend of native and storage gas. If the Btu rating of the native gas is low, then gas delivered back into the system must be enriched (typically with propane) before delivery. Although this can be done for small differences, to make significant adjustments is difficult and expensive. Thus, native gas should probably be at least 900 Btu and, the closer to 1,000 the better.

- Field pressures. The higher the initial pressure of a field, the higher the pressures that need to be attained for storage. Pressure is attained through compression. Compression is expensive in terms of the cost of equipment, maintenance of equipment, and fuel for operations.

- Location vis-à-vis delivery pipelines with available delivery capabilities to receive and redeliver gas to and from the gas storage field. The ability to inject and withdraw gas in required quantities is a requisite for storage. Thus, the field has to be in reasonable locus to a major high pressure pipeline with capacity for serving the field and its storage customers.

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Financial Comments[15]

- Market-based rate projects must be able to be commercially financeable. There are no ratepayers to finance the development of the project. That is: it must have a price tag that will attract investors and will repay the investors and provide a reasonable return on their investment. The first phase of this is a very risky type of investment, it takes considerable cash and can be prolonged for several years determining actual feasibility; as a result, to attract investors, it requires a good long-term payout.

- In the attached financial model of each field: the construction debt has been allocated 60% in the first year of construction and 40% in the second. In addition, the start up costs and the placement costs of debt are assigned as debt payments in year 3.

Comments on Individual Fields

On each field, a budget has been prepared showing all of the costs of development in an identical format. The financial worksheets are as follow:

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(Cont.)

[15] Financial worksheets were prepared by Nicole Houston, CPA and are appended.

Snodgrass Slough – Financial Analysis
(in thousands)

	Year 3*	Year 7	Year 12
Projected Revenue	$4,600	$4,979	$5,497
Projected Operating Expense	$4,000	$4,679	$5,693
Projected Debt Service			
Principal	$8,737	$15,883	$27,605
Interest	$8,305	$12,127	$19,584
Remaining Debt	$95,076	$135,708	$217,193
Annual Cash Flow	($16,442)	($27,710)	($47,384)

* Year 1 & 2 are for development of the project. Year 3 is the first year of commercial operation.

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(Cont.)

Freeport Gas – Financial Analysis
(in thousands)

	Year 3*	Year 7	Year 12
Projected Revenue	$3,600	$3,897	$4,302
Projected Operating Expense	$4,000	$4,679	$5,693
Projected Debt Service			
Principal	$5,921	$11,197	$20,102
Interest	$8,305	$12,127	$19,584
Remaining Debt	$65,303	$97,789	$163,845
Annual Cash Flow	($12,018)	($20,699)	($36,209)

* Year 1 & 2 are for development of the project. Year 3 is the first year of commercial operation

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(Cont.)

Thornton Gas – Financial Analysis
(in thousands)

	Year 3*	Year 7	Year 12
Projected Revenue	$15,000	$16,236	$17,926
Projected Operating Expense	$4,000	$4,679	$5,693
Projected Debt Service			
Principal	$20,643	$32,509	$49,736
Interest	$18,788	$22,911	$30,355
Remaining Debt	$214,216	$253,874	$328,702
Annual Cash Flow	($28,431)	($43,863)	($67,858)

* Year 1 & 2 are for development of the project. Year 3 is the first year of commercial operation

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(Cont.)

Thornton Gas – Financial Analysis (alternative Budget)
(Complete Field Build-out)
(in thousands)

	Year 3*	Year 7	Year 12
Projected Revenue	$36,000	$38,968	$17,926
Projected Operating Expense	$4,000	$4,679	$5,693
Projected Debt Service			
Principal	$28,421	$36,052	$42,149
Interest	$24,403	$21,617	$14,827
Remaining Debt	$276,619	$234,166	$143,196
Annual Cash Flow	($20,825)	($23,382)	($19,646)

* Year 1 & 2 are for development of the project. Year 3 is the first year of commercial operation

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(Cont.)

The following provides individual comments about each field. A DOGGR[16] map of each field is appended at the end of this document.

Snodgrass Slough

This is a very deep field for storage operations. It would require at least 7500 hp of compression (3 compressors), perhaps 10,000 Hp. It would likely be rejected on this basis alone. However, at a capacity of 3.2 Bcf, it also would be found to be too small to be either economically viable or to meet SMUD's needs for 4 Bcf. The Btu rating of native gas is low thus requiring enrichment on withdrawal. Finally, it would require about 6 miles of pipelines, part of which would be through environmentally sensitive areas.

A cash flow model of the field shows that in the first year of operation it would lose about $16,000,000 and the losses would increase in subsequent years as the debt increases. The debt on the project would start at $95,000,000 and over the first ten years of operation would increase to over $217,000,000. The investors would receive no return on investment. The project is not economically viable and therefore could not be funded and built.

The map of the field shows gas produced in the north end of the field and in the south west end of the field. This suggests that there may be 2 pockets of gas that are not connected interspersed with and surrounded by dry holes.

Freeport Field

The Freeport Field is located at the site of the wastewater treatment plant. It is deeper than is preferable and would require perhaps 7500 hp of compression. The quality of native gas is very poor causing the need for significant enrichment with associated operating problems on withdrawal. With less than 2 Bcf of storage capacity, it is too small to be either economically viable or to meet SMUD's needs for 4 Bcf.

A cash flow model shows this project losing about $12,000,000 the first year. Over ten years of operation the debt would increase from over $65,000,000 to over $160,000,000. There is no return to the investors. This project cannot be funded and built.

The map of the field suggests 3 pockets of gas. That is because the 3 good wells are separated by dry holes. If this is the case, the field would have to be operated as 3 individual very small projects. This would be extremely difficult.

Thornton Field

The Thornton Field is a large gas field which produced 54 Bcf of gas. The major deficits of this field are first that much of it lies in a nature preserve and secondly that it would need an excessive amount of "Pad" gas. It would also require about 10 miles of pipeline.

Although it could conceivably have 36 Bcf of storage capacity; the pipeline capacity to service the field is limited so that it would logically handle about 8 Bcf of gas (which is

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[16] DOGGR is the acronym for California Division of Oil, Gas and Geothermal Resources.

comparable to the Florin project) with a reasonable annual turn-over (perhaps 2 turn service). This is not competitive for economic viability.

In considering a cash flow model, we have proposed that this be a 7.5 Bcf project (the same as Florin). The project would lose about $28,000,000 in the first year substantially more in subsequent years. The Thornton project is not economically viable and therefore cannot be built.

The field map shows 15 successful locations surrounded by 22 dry holes. This is a very large and complex field with communication between wells throughout the approximately 7000 acres comprising the field. Geological maps show the total field as being in communication (a great field for production; a difficult field for storage).

Thornton Alternate Project – complete build-out of field

This project utilizes the full capacity of the field. This can be accomplished by the incorporation of a 22 mile pipeline from the field to the PG&E backbone system (in addition to a pipeline connection with the SMUD line), additional wells and compression. The pipeline would extend from the field into the Sacramento Delta, across a number of Islands including Sherman Island (a natural habitat), with 5 or 6 major river crossings and tying into PG&E on Sherman Island.

The project would be constructed partially in the Cosumnes River Preserve and partially just south of the preserve (see attached map).

Because of the volume of gas included in the project, the price per Mcf would be reduced as it would be in direct competition with PG&E, Lodi< Wild Goose, the new Central Valley project and 2 other projects that are in process.

In the first year, the income would be a negative twenty million, this would reduce slightly over the first 10 years of operation. The cost would be over $300,000,000, the remaining debt would be close to $150,000,000 after ten years of operation. This is not fundable.

Florin Field (The Project)

The Florin Field is of reasonable depth, the Btu rating of native gas is about 920. It will require 2 ½ miles of pipeline all through industrial zoned area. It will not require any pad gas as the field was not totally depleted. Originally it contained about 13 ½ Bcf of natural gas of which 8.2 Bcf was produced thus leaving 5+ Bcf in place that will be utilized as pad gas. Whereas the original field pressure was 1518 Psi, the pressure at abandonment was still 1115 Psi. This is a good field for storage. As stated above, the cost/return structure at Florin is such that the project will be economically viable and can be funded and built.

Summary

From an economic perspective, none of the three fields proposed by the EIR is economically viable. In round numbers, the following would be the economic return for each field, at the end of 10 years after the start of operations:

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	Snodgrass Slough	Freeport Gas	Thornton	Thornton Alt.
Annual Income	- $47,384,000	- $36,209,000	- $67,858,000	-$19,646,000
Remaining Debt	- $95,076,000	- $20,699,000	- $328,702,000	- $143,196,000

Florin is the only project that would have paid off the debt at the end of 10 years and have a positive cash flow for return to investors. None of other projects would either pay off the debt or make a return on investment. As a result, none of the three alternatives is fundable. Thus, from an economic perspective, the only project alternative is no project.

In summary, the only field that is of appropriate size, geologically a good candidate and economically developable among the proposed project and suggested alternatives is the Florin Gas Field.

D2-299 (Cont.)