Complete	Incomplete (no further request at this time)	Incomplete (additional request)	Response Under Review	No Applicant Response

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
			Deficiency Request #1				
1.1	**Summary**						
1.1-1	General		Please provide the PEA original files (Word, Excel, jpeg/images, etc.).	10/30/15			
1.1-2	General - GIS Data		Provide GIS data for the entire SDG&E/SoCalGas natural gas transmission system within SDG&E's service area. This can be on a web site that is password protected to maintain security.	10/30/15			
1.1-3	General - GIS Data		Provide GIS shapefiles for Lines 1600 and 3010 to allow for CPUC/consultant preparation of figures, generating calculations, and comparing alternatives.	10/30/15			
1.1-4	Agency Involvement: Project Description / MCAS Miramar	p. 1-4, 3-68, 3-70, 3-72 (Table 3-9)	Provide the status of the reimbursement agreement with MCAS Miramar.	10/30/15			Deficiency item copied to Caltrans and Miramar
1.1-5	Agency Involvement: Project Description / MCAS Miramar	p. 1-4, 3-68, 3-70, 3-72 (Table 3-9)	Provide an update on MCAS Miramar review of the Draft Tier 1 application filed in April 2015.	10/30/15			Deficiency item copied to Caltrans and Miramar
1.1-6	Agency Involvement: Project Description / MCAS Miramar	p. 1-4, 3-68, 3-70, 3-72 (Table 3-9)	Provide SDG&E/SoCalGas's anticipated timeline for MCAS Miramar management approval to act as Lead Agency under NEPA. CPUC discussions with MCAS Miramar's Antoinette Perez indicate that acceptance of the Final Tier 1 Application is anticipated to occur before the end of the year. The next step would be to seek management approval of the MOU/MOA with the CPUC for environmental document preparation. Their approval process will include MCAS Miramar management review and approval of the Tier 1 Application and MOU. It appears that this is likely to occur early 2016.	10/30/15			Deficiency item copied to Caltrans and Miramar
1.1-7	Agency Involvement: Project Description / Caltrans / Alternatives	p. 1-4, 3-68, 3-70, 3-72 (Table 3-9), 4.16-3, Ch 5	Provide a discussion of Caltran discretionary authority over the proposed project. Chapter 5 states in several places that Caltrans may not permit the proposed route or an alternative. Update the discussion on p. 1-4 and p. 4.16-3 with information about how Caltrans will rely on the EIR/EIS in their permitting processes for the proposed project. Describe possible outcomes and delays if Caltrans finds that the certified EIR/EIS is later found to be deficient for their permitting purposes?	10/30/15			Deficiency item copies to Caltrans and Miramar
1.1-8	Agency Involvement: Project Description / Caltrans /Alternatives	p. 1-4, 3-68, 3-70, 3-72 (Table 3-9), 4.16-3	Discuss the possibility of a reimbursement mechanism similar to the one in process with MCAS Miramar for Caltrans to take an active role early in the EIR/EIS process to help ensure that the document meets their permitting requirements. It is anticipated that Caltrans may be a signatory on the MOU with Miramar. Caltrans met internally about this project on 10/23/15. The CPUC will follow up with Ann Fox, Amy Vargas, and Bruce April at Caltrans as soon as possible to further discuss the MOU.	10/30/15			Deficiency item copied to Caltrans and Miramar
1.1-9	Agency Involvement: Project Description / Caltrans / Alternatives	p. 1-4, 3-68, 3-70, 3-72 (Table 3-9), 4.16-3, Ch 5	a. FHWA delegated NEPA responsibility to Caltrans in 2012 (see http://www.dot.ca.gov/hq/env/nepa). Discuss the possibility of Caltrans acting as the Lead Agency under NEPA. About 20 miles of the proposed 47-mile pipeline would generally follow the alignment of U.S. Route 395 (PEA cites Old Hwy 395) and Interstate 15U.S. Route 395, Interstate 15, and several other State Routes would be crossed. 41 miles of the pipeline would be installed within roadways and road shoulders. About 3.5 miles of the pipeline would cross land within MCAS Miramar. b. Confirm whether U.S. Route 395 is a federal/state roadway or if it is now under county jurisdiction and not federal/state jurisdiction along the entire alignment of the proposed pipeline.	10/30/15			Deficiency item copied to Caltrans and Miramar
1.1-10	Project Description / Caltrans / Alternatives	p. 1-4, 3-68, 3-70, 3-72 (Table 3-9), 4.16-3	Provide a list of Caltrans attendees involved at the October 2014, November 2014, February 2015, and June 2015 meetings. Provide meeting minutes if available.	10/30/15			Deficiency item copied to Caltrans and Miramar
1.1-11	Agency Involvement: Project Description / Caltrans	p. 1-4, 3-68, 3-70, 3-72 (Table 3-9), 4.16-3	Provide a copy of the encroachment permit issued by Caltrans on March 26, 2015 for survey activities and all associated permit documentation.	10/30/15			Deficiency item copied to Caltrans and Miramar
1.1-12	Agency Involvement: Project Description / Caltrans	p. 1-4, 3-68, 3-70, 3-72 (Table 3-9), 4.16-3	Provide an update on all Caltrans engagement activities with respect to the proposed project.	10/30/15			Deficiency item copied to Caltrans and Miramar
1.1-13	Agency Involvement: Project Description, Alternatives / USFWS	p. 1-4, 1-5, Ch. 4, Ch. 5	Estimate how many miles of critical habitat are crossed by the proposed route, Line 1600, and Line 3010.	10/30/15			
1.1-14	Agency Involvement: Project Description / USFWS	p. 1-4, 1-5	Provide a contact list of the USFWS representative(s) contacted by SDG&E/SoCalGas and Insignia. Provide the contact letters or point to the location in the PEA where these are located. The PEA states on p. 1-5 that no comments from USFWS about the proposed project have been received.	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
			Deficiency Request #1				
1.1-15	Agency Involvement: Project Description / CDFW	p. 1-4, 1-5	PEA Section 1.4 does not indicate that CDFW has been contacted. Please explain. If CDFW has been contacted, provide a contact list of the CDFW representative(s) contacted by SDG&E/SoCalGas and Insignia regarding the proposed project and contact dates. Update PEA Section 1.4 with and a discussion of these contacts.	10/30/15			
1.1-16	Agency Involvement: Project Description, Hydrology / USACE, CDFW	p. 1-4, 1-5, Ch. 4, Ch. 5, Table 4.9-2.	Which of the 11 water features identified in Table 4.9-2 are expected to be (1) federal jurisdictional or (2) state jurisdictional? Update Table 4.9-2 with this information.	10/30/15			
1.1-17	Agency Involvement: Project Description, Bio / USACE, CDFW	p. 1-4, 1-5, Ch. 4, Ch. 5, Table 4.4-10, 4.4-11	Update Tables 4.4-10 and 4.4-11 with the specific number of unique features that would be impacted. Add a column to each table. For example, state X number of ephemeral drainages would be impacted along the proposed alignment.	10/30/15			
1.1-18	Agency Involvement: Project Description / USACE	p. 1-4, 1-5	Provide a contact list of the USACE representative(s) contacted by SDG&E/SoCalGas and Insignia. Provide the contact letters or point to the location in the PEA where these are located.	10/30/15			
1.1-19	Agency Involvement: Project Description / SWRCB, RWQCB	p. 1-4, 1-5	Provide a contact list of the SWRCB and RWQCB representative(s) contacted by SDG&E/SoCalGas and Insignia. Provide the contact letters or point to the location in the PEA where these are located.	10/30/15			
1.1-20	Public Outreach	p. 1-42	Provide a summary of outreach efforts to date including media press releases, notifications, and newspaper ads; stakeholder meetings; emails and other stakeholder communication methods; summary of attendance at the open houses and comments. Discuss the strategies employed for determining the locations of open houses including initial polling efforts.	10/30/15			
1.1-21	Public Outreach	p. 1-42	Provide a report of the results, methodology, participation numbers, and timing of all polling conducted by SDG&E/SoCalGas for the proposed project.	10/30/15			
1.1-22	Public Outreach	p. 1-42	Provide a mailing list in Excel that contains all land owners within 300 feet of the proposed pipeline right-of-way, all federal, state, and local agency contacts (both contacts already made and those anticipated), and updates from returned postcards and additions from the SDG&E open houses and other stakeholder outreach efforts. Group the mailing list by color code or some other clear identifier (e.g., a new column) to identify where the address originated.	10/30/15			
1.2	**Project Purpose and Need**						
1.2-1	Purpose and Need	Ch. 2 / New Appendix	The CPUC continues to discuss the parameters for a **cost-benefit analysis** (economic analysis) for the proposed project. It is not clear at this time to what extent all or part of such an analysis may be required as part of the PEA. This is a placeholder for a deficiency item.	10/30/15			Placeholder for a deficiency item
1.2-2	Purpose and Need	Ch. 2	**Past Discussions with the CPUC:** a. Provide a comprehensive discussion that cites specific CPUC proceedings, rulings, gas capacity filings, other documents, and ex parte communications regarding SDG&E/SoCalGas's dialogue with the CPUC since the 1990s (or longer if applicable) regarding SDG&E/SoCalGas's redundancy concerns associated with lines 3010 and 1600 and gas supply to SDG&E service area. Include in the discussion any reference to gas supply to SDG&E's service area from Otay Mesa. b. Provide a copy of all SDG&E Gas Capacity Planning filings filed pursuant to OII .I-11-002 since CPUC Decision 02-11-073.	10/30/15			
1.2-3	Purpose and Need	p.2-1	Add the Marine Corps' purpose and need for the project under NEPA.	10/30/15			
1.2-4	Purpose and Need	p.2-1	The growth of renewable energy in California is projected to be 50% by 2030 along with reduction of greenhouse gas emissions as required under SB 350. In addition, projections of natural gas use have not increased but have remained flat or decreased (CEC). Please explain how the proposed project would be needed with the increase in use of renewable energy.	10/30/15			
1.2-5	Purpose and Need	p.2-1	The Secretary of the Navy established renewable energy goals for the Navy and Marine Corp's shore-based installations to be met by 2020. In addition, the federal government has renewable energy policies contained in the following: - Executive Order (EO) 13514, Federal Leadership in Environmental, Energy, and Economic Performance (2009) - Energy Policy Act of 2005 (EPAct) (42 United States Code [U.S.C.] 15852 - Title 10 U.S.C. 2911(e) In December 2013, President Obama signed a presidential memorandum that requires federal	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
			agencies to produce or procure from renewable sources 20 percent of electricity consumed by facilities by FY 2020 and each FY thereafter, an amount that represents a more aggressive goal than under the EPAct or 10 U.S.C. 2911(e). The memorandum also establishes interim goals of 10 percent by 2015, 15 percent by 2016, and 17.5 percent by 2018. In support of the EPAct and 10 U.S.C. 2911(e) renewable energy goals, the Secretary of the Navy created the 1 Gigawatt (GW) Initiative—named for the amount of renewable energy generation capacity to be deployed by 2020 (Navy 2012), either on or near Navy and/or Marine Corps installations. Please explain how the proposed project would be consistent with these renewable energy goals.				
1.2-6	Purpose and Need / Alternatives	Ch. 2, 5	The CPUC proposes the following revisions to clarify Objectives 1, 2, and 3 as unique project objectives. If SDG&E/SoCalGas objects to any of the following revisions, provide a reasoned explanation. See also Deficiency Items 1.2-7 and 1.2-8 regarding redundancy and operational flexibility/capacity. 1. ***Implement Pipeline Safety Requirements for Existing Line 1600*** ~~and Modernize the System with State-of-the-Art Materials~~: ~~Enable the Applicants to~~ comply with the CPUC approved PSEP ~~by replacing Line 1600 with a new gas transmission pipeline~~ as soon as ~~is~~ practicable by either hydrotesting and repairing Line 1600, replacing Line 1600 without hydrotesting, abandoning Line 1600 in place, or permanently lowering the pressure of Line 1600 for use as a distribution line instead of a transmission line. ~~Construction of the new line will enable the use of Line 1600 for distribution while operating at a lower pressure. This replacement will not only comply with the PSEP, but it will also add a greater margin of safety by replacing Line 1600's transmission function with a new pipeline by using modern, state-of-the-art materials. In addition, replacement would avoid any potential customer impacts associated with pressure testing Line 1600.~~ 2. ***Improve System Reliability*** ~~and Resiliency~~ ***by*** ~~Minimizing~~ ***Reducing Dependence on a Single Pipeline:*** ~~Simultaneously~~ Improve the reliability ~~and resiliency~~ of the integrated SDG&E and SoCalGas natural gas transmission system (Gas System) by replacing Line 1600 ~~with a 36-inch-diameter gas transmission pipeline~~ so that core and noncore customers will continue to receive gas service in San Diego in the event of a planned or unplanned service reduction ~~or outage~~ of the existing 30-inch-diameter Line 3010 or the Moreno Compressor Station. San Diego County ~~is essentially completely reliant~~ relies on the compressor station in the City of Moreno Valley and Line 3010 to~~, which together~~ provide approximately 90 percent of SDG&E's capacity. ~~The Applicants are not aware of any other major metropolitan area that is so dependent on a single pipeline. A system outage on Line 3010 or the Moreno Compressor Station would constrain available capacity in San Diego, which may lead to gas curtailments. This would be alleviated with the new 36-inch-diameter line providing resiliency for both Line 3010 and the Moreno Compressor Station.~~ 3. ***Enhance Operational Flexibility to Manage Stress Conditions by Increasing System Capacity:*** ~~Simultaneously~~ Increase ~~the transmission~~ capacity of the Gas System in San ~~Diego County by approximately 200 million cubic feet per day (MMcfd) as a result of the PSEP compliance replacement line being 36 inches in diameter so that~~ to enable the management of ~~the Applicants can reliably manage the~~ fluctuating peak demand ~~of core and noncore customers, including electric generation and clean transportation. The new line would provide incremental Increased pipeline capacity that would give flexibility to operate the SDG&E system by expanding the options available to handle stress conditions on a daily and hourly basis that put system integrity and customer service at risk~~.	10/30/15			
1.2-7	Purpose and Need / Alternatives	Ch. 2, 5	**Redundancy:** If providing system redundancy is an objective of the proposed project, please	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
			state this as an objective separate from the reliability objective. Reliability and redundancy as objectives have very different implied costs, and there are alternatives to the proposed project that would likely meet the reliability objective but would not meet a redundancy objective.				
1.2-8	Purpose and Need / Alternatives	Ch. 2, 5	**Operational Flexibility/Capacity:** Discuss the potential for separating the Operational Flexibility objective from the Capacity Increase objective. To what extent and in what ways can the proposed project provide operational flexibility separate from the provision for increased capacity?	10/30/15			
1.2-9	Purpose and Need / Alternatives	Ch. 2, 5	**Cost of Gas to Ratepayers:** To what extent would the project, as proposed, reduce the cost of natural gas to ratepayers in SDG&E's service area? If the project would increase access to inexpensive natural gas, provide a discussion that considers this as an objective to the proposed project.	10/30/15			
1.2-10	Purpose and Need / Alternatives	Ch. 2, 5	**Underlying Project Purpose/Objectives:** To what extent does any one of the three objectives presented in the PEA reflect the underlying purpose of the proposed project? The CPUC understands, for example, that the project would not have been proposed but for the need for Line 1600 to comply with *PSEP*—Pipeline Safety Enhancement Plan (A.11-11-002, D.14-06-007)—as required by the CPUC.	10/30/15			
1.2-11	Purpose and Need / Alternatives	Ch. 2, 5 / Response from Neil Navin on 9.29/15 (proposed 200 MMcfd capacity increase)	**System Capacity:** a. With regard to the response on 9/29/15 (see attached image in the notes column), explain whether the capacities shown on the table assume that the North-South pipeline project, including increased compression, is operating. If the table capacities are calculated assuming that no North-South project would exist, including added compression, please provide revised capacity numbers including the North-South project and associated compression. b. With regard to the "hard limit" of the pipeline capacities shown on the table, please explain in more detail why this hard limit exists. c. Please also explain whether increased compression capacity at Rainbow (or elsewhere on the SoCalGas/SDG&E system) would increase the pipeline capacities shown on the table. d. Please explain in greater detail why additional capacity would not be available from Line 1600 even though it is de-rated. Assuming some capacity would be provided, regardless of how small the additional capacity may be, provide an estimate for the additional capacity for (1) de-rated Line 1600; and (2) distribution Line 1026. In prior presentations to the CPUC, for example, SDG&E/SoCalGas indicated that less than 1% of the gas supply to SDG&D's service area comes from Line 1026. What is this amount in MMcfd? e. Your response indicates that each pipeline individually has a larger capacity alone than when operating as part of the system. There is no "lost" capacity on Line 3010 if Line 3602 is installed. Provide the maximum design delivery capacities individually of Lines 1026, 1600, 3010, and the proposed 3602.	10/30/15			Attachment 1
1.2-12	Purpose and Need / Alternatives	Ch. 2, 5	**Recorded and Forecast Peak Gas Demand.** Complete the attached Table 2-1, which was originally sent to SDG&E/SoCalGas for completion and inclusion in the PEA on 8/10/15.	10/30/15			Attachment 2
1.2-13	Purpose and Need / Alternatives	Ch. 2, 5	Provide an explanation of the increase (spike) in natural **gas demand for electric generation on July 2, 2015**. Also provide a thorough discussion of this type of event with estimates of how often it has, and is expected to, occur. Include historical data of actual events and the resultant power loss to various types of customers as well as forecast data used to estimate the probability of reoccurrences. See attached slide presented to CPUC Energy Division management on 8/20/15.	10/30/15			See attached slide from 8/20/15 presentation to CPUC
1.2-14	Purpose and Need / Alternatives	Ch. 2, 5	Address the following points based on the latest **Gas Capacity Forecast (October 2015)** filing to the CPUC: a. The filing states that "despite predicted declines in natural gas demand on an annual basis," SDG&E/SoCalGas is not forecasting declines on a peak-day design standard as shown in	10/30/15			SDG&E/SoCalGas Gas Capacity Planning Reports (October 2015)

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
			Table 1. Table 1 identifies Peak Daily Demand forecasts pursuant to the adopted Peak Day design standard. However, Table 1 indicates that daily peak gas demand will decline from the forecast for 2015/16 of 607 MMcfd to 589 MMcfd in 2024/2025. The table does not forecast that any day in the next 10 years will experience total gas demand exceeding 590 MMcfd. Total demand is then shown to increase after 10 years, starting in 2025/26 (591 MMcfd). Explain why the forecast shows an increase that begins 10 years from 2015 and reaches 617 MMcfd in 2035/36. Note that natural gas demand for Electrical Generation (EG) is expected to consistently decrease from 199 MMcfd in 2015/16 to 174 MMcfd in 2035/36. The only increase through the planning period is in Core demand, which jumps from 354 MMcfd to 382 MMcfd in the 10-year period after 2025 that leads to 2035/36. Please explain and include supporting data. b. The filing states that sudden changes in an operating day are not typically considered in the development of a formal demand forecast but that this consideration is anticipated to become more common. Who anticipates this? When would this become more common? Discuss when and how SDG&E/SoCalGas plans to file requests with the CPUC for such additional considerations in formal forecasts. If a proceeding(s) is already underway, identify the proceeding(s).				
1.3	**Project Description**						
1.3-1	Design	p. 3-10	Explain why 800 psig is the designated Maximum Allowable Operating Pressure? Modern natural gas pipeline design standards allow for much larger pressures to be achieved (i.e., greater than 1000 psig).	10/30/15			
1.3-2	Design	p. 3-10	Explain the rationale for determining that a 36-inch pipeline (precisely this diameter) is needed.	10/30/15			
1.3-3	Project Description	p. 3-41	Estimate the type and number of generators that will be required for power at contractor yards.	10/30/15			
1.3-4	Project Description	p. 3-42	Provide a draft blasting plan that describes: - the types of blasting that may be used during construction of the proposed project - methods to be used to minimize hole-to-hole propagation - types of explosives/initiation system that may be used - anticipated drill and blast pattern - charge weights and delays - methods for controlling flyrock - selection of blasting products and methods - monitoring, reporting, and controlling ground cracking and displacement - explosives storage and transportation procedures - peak particle velocity monitoring and control - fire prevention - methods and protocols to protect human health and safety and - APMs to minimize impacts on sensitive receptors, wildlife, aquatic features, and paleontological resources	10/30/15			
1.3-5	Project Description	p. 3-47	Identify potential disposal facilities for export soil. Estimate the total number of truck trips required to transport export soil to each potential disposal facility. Provide the average one-way mileage from the source that the export soil is generated to the potential disposal facility. Provide an estimate of the duration of the soil export generating activities associated with each potential disposal facility. Provide an estimate of the number of truck trips per day to transport export soil from the locations that the export soil is generated to each potential disposal facility. Provide the total miles required to transport export soil to each potential soil disposal facility.	10/30/15			Similar to PEA Attachment 4.16B.
1.3-6	Project Description	p. 3-55	Describe the process for detecting and avoiding frac-out during HDD operations. Provide additional detail on measures that the frac-out contingency plan will include.	10/30/15			
1.3-7	Project Description	p. 3-62	Identify potential sources of imported rock-free sand for pipeline padding. Estimate the volume of sand that will be needed for pipeline padding. Estimate the total number of truck trips	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
			required to transport the sand from each potential source. Provide the average one way mileage from each potential sand source to the locations that it will be used. Provide an estimate of the duration of sand padding activities for each location of the pipeline that will use sand from each potential source. Provide an estimate of the number of truck trips per day to transport the sand from each potential source to the portion of the pipeline that will use sand from that potential source. Provide the total miles required to transport sand from each potential source to the portions of the pipeline that may use that potential source.				
1.3-8	Project Description	p.3-62	Identify potential sources of sand/slurry mixture needed for backfill in urban areas. Estimate the total volume of sand/slurry backfill that will be needed for pipeline construction. Estimate the total number of truck trips required to transport the sand/slurry mixture from each potential source. Provide the average one way mileage from each potential sand/slurry mixture source to the locations that it will be used. Provide an estimate of the duration of sand/slurry backfill activities for each location of the pipeline that will use sand/slurry mixture from each potential source. Provide an estimate of the number of truck trips per day to transport the sand/slurry mixture from each potential source to the portion of the pipeline that will use sand/slurry from that potential source. Provide the total miles required to transport sand/slurry from each potential source to the portions of the pipeline that may use that potential source.	10/30/15			Similar to PEA Attachment 4.16B.
1.3-9	Project Description	p.3-65	Identify potential disposal and/or recycling facilities for construction materials and debris (e.g., concrete, asphalt, other construction materials) to be disposed of, other than export soil. Estimate the total number of truck trips required to transport construction materials and debris to each potential recycling and/or disposal facility. Provide the average one-way mileage from the source of the construction materials and debris to the potential disposal and/or recycling facility. Provide an estimate of the duration of construction materials and debris-generating activities associated with each potential disposal and/or recycling facility. Provide an estimate of the number of truck trips per day to transport construction materials and debris from the locations that the materials or debris are generated to each potential disposal and/or recycling facility. Provide the total miles required to transport construction materials and debris to each potential disposal and/or recycling facility.	10/30/15			Similar to PEA Attachment 4.16B.
1.3-10	Project Description	p.3-21	Update Table 3-1 with the other I-15 crossing (at approximately MP 3).	10/30/15			
1.3-11	Project Description		At our meeting on 10/28/15, Estela de Llanos discussed consultation with CALTRANS and the potential for changes in the proposed I-15 crossings and pipeline alignment. Provide her response in writing including further discussion of next steps and timing for coordination with Caltrans.	10/30/15			
1.4	**Environmental Impact Assessment**						
1.4.1	**Aesthetics**						
1.4.1-1	Aesthetics	Maps 1-5	Show and label the locations of the visual character photos on project maps at the scale of maps provided as Attachment 3-A (Detailed Route Map). In addition, show and label on these maps the following: - County Scenic Highways and other eligible or designated scenic roads; - Scenic vistas identified in the PEA and other scenic features identified in local plans or related documents; - Municipal, county, and other administrative boundaries; - Any trails, parks, or other recreation or open space facilities within 0.5 mile of the proposed ROW; - all locations where mature trees and/or large shrubs will be removed for construction; and all project features for construction or operation.	10/30/15			
1.4.1-2	Visual Simulations	Figure 4.1-1	Provide additional visual simulations showing the appearance of the ROW and any other project features 1) immediately following construction and 2) 3-5 years after construction. These additional visual simulations are to be prepared as panoramas to show the context of the views and are to be prepared for the following locations identified below where the grading and vegetation removal would be required. If, for any of these locations, the proposed pipeline would be placed within an existing paved roadway and no existing vegetation removed, an additional visual simulation would not be required for that location.	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
			- View from Mission Road (a County-designated Scenic Highway) in the vicinity of Photo Location 5 showing the proposed ROW with grading and vegetation removal. - Views from I-15 (a County-designated Scenic Highway and Eligible State Scenic Highway) in the vicinity of Photo Locations 3, 4, 6, and 13 showing the proposed ROW with grading and vegetation removal in locations where views of the ROW would not be screened by existing vegetation or terrain. - View from the vicinity of the trailhead at Highland Valley Road and Pomerado Road showing the proposed ROW with grading and vegetation removal. View looking south toward MLV 7 from the vicinity of the trail and parkway showing the proposed MLV and ROW with grading and vegetation removal.				
1.4.1-3	Aesthetics	p. 4.1-8	Under the heading “Potentially Affected Public Views”, the PEA states: “Because the Proposed Project is predominantly located underground, only the aboveground facility locations will be visible to the public.” In addition to describing and assessing aesthetic impacts for above-ground project elements, describe the appearance and assess the aesthetic impacts of the proposed ROW for all locations where grading and vegetation removal and reclamation would occur and the ROW may be visible to viewers from parks, trails, roadways, residential areas, open space areas, and other areas accessible to the general public.	10/30/15			
1.4.2	**Agriculture and Forest Resources**		No Deficiencies				
1.4.3	**Air Resources**						
1.4.3-1	Air Resources	p. 4.3-4, Table 4.3-1	The Table for Ambient Air Quality Standards needs to be updated. Federal Annual mean for PM10 should be N/A; Update SO2 and Lead according to designation: ‘The 1971 SO2 national standards (24-hour and annual) remain in effect until one year after an area is designated for the 2010 standard, except that in areas designated nonattainment for the 1971 standards, the 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standards are approved.’ ‘The national standard for lead was revised on October 15, 2008 to a rolling 3-month average. The 1978 lead standard (1.5 µg/m3 as a quarterly average) remains in effect until one year after an area is designated for the 2008 standard, except that in areas designated nonattainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.’ (e.g., http://www.arb.ca.gov/research/aaqs/aaqs2.pdf)	10/30/15			
1.4.3-2	Air Resources	p. 4.3-1	Chapter 3 (Project Description) indicates that the Rainbow Metering Station is located at the Riverside-San Diego county line. In this case, both the San Diego County Air Basin (SDAB) and the South Coast Air Basin (SCAB) would be involved. The portion of the project within the SDAB would be subject to the San Diego County Air Pollution Control District (SDAPCD) rules and regulations, and the northern portion of the Rainbow Pressure-Limiting Station will be subject to the South Coast Air Quality Management District (SCAQMD) rules and regulations.	10/30/15			
1.4.3-3	Air Resources	Note 2, p. 4.3-14	The analysis does not include air quality impacts associated with purging the pre-lay segment of existing pipe, or with providing a temporary portable natural gas system for the existing distribution pipelines connected to the pre-lay segment. It is stated that these activities are not anticipated to affect the significance findings of the section. The additional impacts above should be accounted for as a conservative estimate, or a more detailed assessment of why the additional impacts are not affecting the results should be given, and supported.	10/30/15			
1.4.3-4	Air Resources	p. 4.3-16	Construction emissions of PM10, CO, and NOx would exceed the applicable SDAPCD thresholds even after applying the proposed mitigation measures. Other forms of mitigation beyond those already proposed or available in CalEEMod should be considered.	10/30/15			
1.4.3-5	Fugitive Dust Emissions	p. 4.3-18	Impacts from fugitive dusts need to be quantified, in order to state that they are less than significant. Simple implementation of mitigation measure APM-AIR-01 does not determine the level of impact.	10/30/15			
1.4.3-6	Construction Equipment and	p. 4.3-18	Since impacts associated with construction will be potentially significant, other mitigation	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
	Worker Vehicle Exhaust		measures should be explored. Depending on the local District's regulations, a plan may have to be proposed to further mitigate or offset the emissions in exceedance of the thresholds. Also, because of the exceedances, and depending on the effects of the additional mitigation, dispersion modeling may be necessary to establish compliance with the State and Federal Ambient Air Quality Standards (Table 4.3-1).				
1.4.3-7	Toxic Air Contaminants	p. 4.3-18	The impacts on sensitive receptors need to be quantified. The rate of progress of construction activities, the fact that the mobile fleets are expected to be compliant with the ATCMs, and that pollutant emissions in diesel engine exhaust would not exceed applicable federal or state air quality standards do not imply less than significant impacts on sensitive receptors. There are a number of sensitive receptors that will be exposed to pollution concentrations during construction. The pipeline would be located through dense residential communities within the incorporated cities and along smaller isolated residential areas, such as mobile home parks, in the unincorporated areas of San Diego County. In addition a number of schools, parks, ecological preserves, hospitals and other care facilities would be located in the immediate vicinity of the Pipeline. Criteria pollutants and toxic air contaminants produced by ground disturbance and diesel-fueled vehicles and equipment may create an impact on these receptors although the exposure would be transient and temporary during construction. The closest sensitive receptors should be identified and located (As described in Section 4.3.2 Existing Conditions, sensitive receptors have been identified directly adjacent to the Proposed Project alignment). A Health Risk Assessment should be conducted corresponding to the worst case scenarios. The Air Toxics Hot Spots Program Risk Assessment Guidelines of the California Office of Environmental Health Hazard Assessment recommend using the CARB Hotspots Analysis and Reporting Program (HARP2).	10/30/15			
1.4.3-8	Odor and Regulatory Background	Question 4.3e, p. 4.3-20, p. 4.3-2	Please provide the local District and County regulations for odors. Odor impacts need to be assessed according to local regulations, which may include a screening level analysis based on evaluating Project-specific odor impacts according to District's complaint records, and/or application of dispersion modeling. The impacts of releasing 65,800 standard cubic feet of natural gas at the four planned cold tie-ins also need to be assessed. Depending on the meteorological conditions, the odors may quickly dissipate in the atmosphere, but under certain conditions (e.g., stable turbulent boundary layer, low inversion height) the persistence of odors may well create objectionable odors affecting a substantial number of people (Question 4.3 e). Local regulations regarding permissions to release greenhouse gases into the atmosphere should also be checked and presented.	10/30/15			
1.4.4	**Biological Resources**						
1.4.4-1	No survey locations	p. 4.4-51	Please provide a map showing the no survey areas for agricultural land. Please include a justification for not conducting burrowing owl surveys within agricultural areas.	10/30/15			
1.4.4-2	Survey updates	p. 4.4-10	Please provide updated survey results for the arroyo toad at Sites 2 and Site 7.	10/30/15			
1.4.4-3	Survey updates	p. 4.4-8	Please provide survey results for the QCB at the Elliot Field Station.	10/30/15			
1.4.4-4	USFWS	p. 4,4-11	Please provide a summary of communication with the USFWS regarding concurrence of T&E survey results, and pending areas to be surveyed.	10/30/15			
1.4.4-5	Marine Corps Air Station Miramar	p. 4.4-9	Are additional surveys for the least Bell's vireo and the southwestern willow flycatcher proposed? Will the USFWS accept the 2011 survey results?	10/30/15			
1.4.4-6	GIS Data	p. 4.4-6	Please provide GIS data for the vegetation communities mapped during surveys.	10/30/15			
1.4.4-7	Wetlands and Waterbodies	p. 4.4-32	Provide formal wetland delineation report and data once available. Provide a copy of the Wetland Delineation and supporting documentation (i.e., data sheets). If verified, provide supporting documentation. Additionally, GIS data of the wetland features should be provided.	10/30/15			
1.4.4-8	Wetlands and Waterbodies	p. 4.4-65	Provide additional detail on conceptual mitigation and restoration of temporary impacts to wetlands and waterbodies.	10/30/15			
1.4.4-9	Wetlands and Waterbodies	p. 4.4-32	Discuss construction and restoration methods proposed for crossing wetlands.	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
			Deficiency Request #1				
1.4.4-10	Wetlands and Waterbodies	p. 4.4-32	Describe typical staging area requirements at waterbody and wetland crossings.	10/30/15			
1.4.4-11	Wetlands and Waterbodies	p. 4.4-32	Provide a table identifying all wetlands, by milepost and length, crossed by the project and the total acreage and acreage of each wetland type that would be affected by construction.	10/30/15			
1.4.5	**Cultural, Tribal, and Paleontological Resources**						
1.4.5-1	Historic Properties	Section 4.5, Attachment 4.5-A	Recommendation for eligibility to NRHP and CRHR were not made for all of the resources. Guidance by CA SHPO indicates that this is a first step in determining the potential for impacts under CEQA. For instance, if an archaeological site, building, structure, etc. is not considered an historical resource, effects would not be considered significant. This methodology (i.e., lack of identification of historic properties) also would not satisfy the requirements of Section 106. - APE does not consider indirect effects (visual, auditory, etc.). - Potential for listing not evaluated. - The APE was not explained with sufficient detail to understand where evaluation was conducted and why the APE was depicted as being smaller than the surveyed areas. Maps in Appendix A are not entirely clear, although APE is depicted on it. - Field methodology is not specific and pertains only to archaeological remains; nothing done to evaluate potential historic structures. - Methodology is missing information on collection/evaluation of artifacts, how sites were delineated, how recording accomplished, etc. - A map with mileposts showing the boundaries of all survey areas was not provided. - Results of the literature search were provided as tables within Appendix B. Table B2; while indicating the location of all sites, the table does not indicate eligibility or importance of the site locations. - Table B3 indicates if outside the survey corridor, but does not indicate location in reference to the APE. To address these deficiencies: - Explain why a survey for architectural/built/aboveground resources was not conducted concurrent with the archaeological survey. - Provide information for the NRHP-eligibility of each resource (e.g., NRHP-listed, including NR number and date listed; previously determined NRHP-eligible; previously evaluated and determined not NRHP-eligible; further evaluation or information necessary to determine NRHP-eligibility; unknown; etc.). Without this information for NRHP-eligibility, it will not be possible to suggest management options for these resources under Section 106, NEPA or CEQA. Similarly information for CRHR-eligibility and any local or civic designations (i.e., City of Escondido or City of San Diego) should also be provided. - Confirm that NPS's databases for NRHP-listed historic properties and National Historic Landmarks have been consulted for the project. Include the relevant information for NRHP-listed historic properties and/or properties designated National Historic Landmarks, such as NR numbers and dates listed and/or designated NHLs for management and treatment purposes under Section 106, NEPA and CEQA. For example, the second paragraph of Section 2.5.4 of the CR report suggested that the Luiseno Ancestral Origin Landscape TCP is an NRHP-listed property. A search of National Park Service's (NPS) database confirmed that it was listed in the NRHP on October 30, 2014 (NR # 14000851). Therefore, while this is a Native American resource, it is also a historic property that will need to be addressed for management and treatment purposes under Section 106, NEPA and CEQA. - Provide revised maps that indicate the APE, the survey area, MPs, areas of prior disturbance, etc.	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
			- Recognizing that the Applicants are not a federal agency, provide documentation (correspondence, meeting minutes, etc.) that the APE was defined in consultation with the CA SHPO, such that the definition of the APE would be consistent with 36 CFR 800.4(a)(1).				
1.4.5-2	APE	Section 4.5	The APE was not correctly defined. As stated on page 29 of the Draft CR report, "The Proposed Project's APE was delineated to ensure the identification of significant cultural resources and historic properties that may be directly or indirectly affected by the Proposed Project and that are listed in or eligible for inclusion in the NRHP, the CRHR, or any local ordinances." However, as stated later on page 29 of the Draft CR report, the APE is defined as "areas that could be affected by the maximum extent of the Proposed Project-related ground disturbance, including all construction, all staging areas, and any temporary construction easements." This appears to suggest that the APE has been defined as the areas within which physical impacts and effects as a result of construction are expected, but does not appear to address areas outside the construction footprint, within which visual or auditory impacts and effects as a result of construction or operation may occur; and does not appear to address areas within which indirect and cumulative impacts and effects may occur.[1, 2]	10/30/15			
1.4.5-3	Surveys	Section 4.5 and Attachment 4.5-A	This comment recognizes that the Proposed Project consists of a buried pipeline primarily located within or immediately adjacent to existing linear corridors, and that aboveground appurtenant facilities are relatively small and generally in locations with similar existing facilities. However, for the purposes of management and treatment of cultural resources and historic properties under Section 106, NEPA and CEQA there is no explanation for how the appropriate level of effort to identify and evaluate cultural resources and historic properties was determined and why additional investigations, such as an architectural survey or a traditional cultural property survey, were not conducted or needed. To address this deficiency: - Provide documentation (correspondence, meeting minutes, etc.) for consultation with the CA SHPO and federally recognized Indian tribes, regarding the type of surveys needed for the Proposed Project, and as appropriate under CEQA, local governments that maintain their own registers of locally significant historic resources. - Clarify whether the CA SHPO was consulted regarding the need for a survey or inventory to identify architectural/built/aboveground resources that may be affected by the Proposed Project, such that identification and evaluation efforts would be consistent with 36 CFR 800.4(b) and (c). - Clarify whether federally recognized Indian tribes, including but not limited to the Pechanga Band of the Luiseño Indians, were consulted regarding the need for a survey or inventory to identify additional TCPs that may be affected by the Proposed Project, such that identification and evaluation efforts would be consistent with 36 CFR 800.4(b) and (c) - Whether such consultation did/did not occur, explain why surveys to identify historic architectural/built/aboveground resources and TCPs that may be visually or auditorily affected by construction or operation of the Proposed Project were not conducted.	10/30/15			
1.4.5-4	Correspondence	Attachment 4.5-A	Letters and documentation of Native American consultation were provided as Appendix C. Please provide the following:	10/30/15			

[1] 36 CFR 800.2(c) is the regulatory citation that identifies the parties that have consultative roles in the Section 106 process. This is not relevant to the APE. 36 CFR 800.16(d) is the correct regulatory citation that defines "area of potential effects:" "*Area of potential effects* means the geographic area or areas within which an undertaking may directly or indirectly cause alterations in the character or use of historic properties, if any such properties exist. The area of potential effects is influenced by the scale and nature of an undertaking and may be different for different kinds of effects caused by the undertaking.

[2] While "cumulative effects" are not well defined in the regulations for implementing Section 106, 800.5(a)(1) states that "Adverse effects may include reasonably foreseeable effects caused by the undertaking that may occur later in time, be farther removed in distance or be cumulative." Additionally, the ACHP's 2013 handbook for integrating NEPA and NHPA compliance requirements indicates that the CEQ regulation definition of cumulative impact is "analogous and instructive."

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
			- Do not see "areas of concern" from Pechanga on Pages 1-7 (see page 45 of Report/Attachment of 4.5) or any meeting notes. - Emails noted in report, but letters are provided – are some forms missing? (e.g., Pala Band of Missouri Indian, Viejas Band of Kumeyaay, and Pauma Band of Luiseno). - No documentation of phone calls with Pechanga Band of Luiseno Indians.				
1.4.6	**Geology, Soils, and Seismicity Regulatory Setting**						
1.4.6-1	Geologic Setting	p. 4.6-6	Add mileposts to Table 4.6-1 to 4.6-4 to relate to locations of particular geologic formations and soil types, respectively	10/30/15			
1.4.6-2	Impacts	p. 4.6-8	Discussion about induced seismicity (or lack thereof)	10/30/15			
1.4.7	**Greenhouse Gas Emissions**						
1.4.7-1	Greenhouse Gas Emissions	p. 4.7-8	Page 3-12 of the PEA states "the existing distribution pipelines will be cut and capped, and the pre-lay segment will be purged of natural gas resulting in the release of approximately 1.02 million cubic feet of natural gas to the atmosphere." Table 4.7-3 includes a footnote indicating that estimated GHG construction emissions do not include purging the pre-lay segment. Provide estimated GHG emissions associated with the release of 1.02 MMcf of natural gas associated with purging the pre-lay segment.	10/30/15			
1.4.7-2	Greenhouse Gas Emissions	p. 4.7-8, 4.7-9 Attachment 4.3-A	Tables 4.7-3 and 4.7-4 include GHG emissions estimates for Cold Tie-In and Blowdown operations, respectively. The calculation methods and assumptions for these emissions are not included in Attachment 4.3-A. Provide the methodology, assumptions, and calculations made to estimate GHG emissions from Cold Tie-In construction and blowdown operations.	10/30/15			
1.4.7-3	Greenhouse Gas Emissions	p. 4.7-6, 4.7-9	Provide source for the following statement included in page 4.7-6 of the PEA: "SDG&E's overall methane emissions rate, the key component of natural gas, was approximately 0.04 percent of the total delivered through the system in 2013." Clarify if these operational emissions are included in Table 4.7-4. Justify assumptions made for operational GHG emissions.	10/30/15			
1.4.7-4	Greenhouse Gas Emissions	p. 4.7-3, 4.7-9	On October 22, 2015, the EPA released a revision to the Greenhouse Gas Reporting Rule, which includes the addition of calculation methods and reporting requirements for greenhouse gas (GHG) emissions blowdowns of natural gas transmission pipelines between compressor stations. a. Clarify whether the existing SDG&E's gas transmission system is subject to the Greenhouse Gas Reporting Rule. If applicable, provide recent operational GHG emissions reported to EPA's Greenhouse Gas Reporting Program. b. Clarify if blowdown emissions estimates reported in Table 4.7-4 are consistent with the recent revisions of the EPA's Greenhouse Gas Reporting Rule.	10/30/15			
1.4.7-5	Greenhouse Gas Emissions	p. 4.7-6, 4.7-9	The proposed project would provide natural gas supply, consistent with SANDAG's Regional Energy Strategy. Discuss the estimated benefit of the proposed Project in terms of avoided CO2 emissions from other energy sources.	10/30/15			
1.4.7-6	Greenhouse Gas Emissions	Attachment 4.3-A Attachment 4.16-B	Pages 531 to 634 of Attachment 4.3-A provide modeling results associated with APM-PUS-01, which assumes emissions from three activities: HDD, Hydrotest, and Pipe Installation. Attachment 4.16-B indicates that four construction activities would require reclaimed water: Pipeline Installation, Laydown Yards, HDD, and Hydrostatic Testing.	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
			Total number of truck trips per activity in Attachment 4.16-B: Pipeline Installation: 646 trips Laydown Yards: 396 trips HDD: 407 trips Hydrostatic testing: 939 trips Total number of hauling truck trips per activity in Attachment 4.3-A: <u>Year 2018</u>: Pipeline Installation: 997 trips HDD: 407 trips Hydrotest: 878 trips <u>Year 2019</u>: Pipe Installation: 46 trips Hydrotest: 62 trips Clarify the apparent discrepancies in the number of activities and number of truck trips associated with pipeline installation and hydrostatic testing.				
1.4.8	**Hazards and Hazardous Materials**						
1.4.8-1	Hazards and Hazardous Materials	4.8-30 4.8a	PEA indicates temporary storage sites will be utilized for hazardous materials. Please provide a list of the substances, quantities of each, and largest container size that will be present and the locations of those storage sites. This information is needed to assess the potential impacts of transportation, use, and disposal as well as to evaluate reasonably foreseeable accident and upset conditions.	10/30/15			
1.4.8-2		4.8-31 Table 4.8-3	Please provide the quantities of hazardous materials that will be used in the project area during construction and the maximum container size that will be used to store each substance in the project area. This information is needed to evaluate reasonably foreseeable accident and upset conditions.	10/30/15			
1.4.8-3		4.8-35, 4.8c	Please provide the quantity of natural gas and frequency of emission events that will occur through blow-down activities related to pipeline start-up and routine operations and maintenance. This information is needed to evaluate anticipated emissions near schools.	10/30/15			
1.4.9	**Hydrology and Water Quality**						
1.4.9-1	Surface Waters	p. 4.12-23	For each surface water body crossed by the project, list its water quality classification, if applicable. Identify any waterbodies with special status such as designated surface water protection areas.	10/30/15			
1.4.10	**Land Use and Planning**		No Deficiencies				
1.4.11	**Mineral Resources**		No Deficiencies				
1.4.12	**Noise**						
1.4.12-1	Noise Mitigation	p. 4.12-23	PEA states "Applicant will incorporate noise attenuation measures into the final design to the extent feasible to reduce operational noise levels from pressure-limiting equipment and to achieve one-hour average sound levels at or below the existing limits provided in the current applicable noise ordinances for the locations of these facilities" Specific information is need on what noise attenuation methods will be employed and what the resulting noise levels will be at the nearest NSAs to the Pressure-limiting Stations.	10/30/15			
1.4.12-2	Construction Equipment	p. 4.12-23	A more specific construction equipment list is needed for pipeline construction and construction of the pressure-limiting facility.	10/30/15			
1.4.13	**Population and Housing**		No Deficiencies				
1.4.14	**Public Services**		No Deficiencies				
1.4.15	**Recreation**		No Deficiencies				

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
			Deficiency Request #1				
1.4.16	**Transportation and Traffic**						
1.4.16-1	Traffic and Transportation	p. 4.16-21	Impact discussion does not adequately address impacts from construction traffic. Please provide a traffic analysis that determines level of service (LOS) for roadway segments and intersections that are likely to be impacted by construction workers and construction vehicles traveling to and from laydown sites. This analysis should compare changes in LOS to significance thresholds from County of San Diego Guidelines for Determining Significance and Report and Content Requirements; City of San Diego Traffic Impact Manual; and City of Escondido Traffic Impact Analysis Guideline. (i.e., measurable increases in vehicle delay, reductions in road speed, changes in volumes/capacity). Please provide methodology for how traffic impacts were analyzed. For example, how was "Potential Temporary LOS Change…" in Table 4.16-5 determined?	10/30/15			
1.4.16-2	Traffic and Transportation	p. 4.16-23	Table 4.16-5 footnote states that peak ADT was calculated assuming all 600 personnel would drive their own personnel vehicles to and from proposed project for an aggregate total of 600 personal vehicle trips. Please clarify if this is 600 round trips (to and from), or if this should be 1,200 personal vehicle trips (one-way). Please provide a trip generation table showing how increase of 254 ADT was calculated. Please provide types of trucks that would be used and clarify if truck trips use a passenger car equivalent factor to account for slower speed and larger size?	10/30/15			
1.4.16-3	Traffic and Transportation	p. 4.16-22	Please provide additional discussion on parking impacts in regards to road segments that have on street parking and potential segments where on-street parking may be disrupted during construction or access to off-street parking may be temporarily closed.	10/30/15			
1.4.16-4	Traffic and Transportation	p. 16	Please clarify how lane capacities were estimated (i.e., using standards from Highway Capacity Manual, or municipal traffic manuals?), and if estimated capacity considers likely need for lower speed through construction zones.	10/30/15			
1.4.16-5	Traffic and Transportation	p. 15	Please provide clarification on which roads would have lanes closed or would be closed completely and an additional discussion of vehicle capacity of identified detour routes.	10/30/15			
1.4.17	**Utilities and Service Systems**						
1.4.17-1	Drilling Mud	p. 3-53 and 4.17-16	Page 3-53 (Project Description) states that where it cannot be reused, excess drilling mud will be disposed of at an appropriate waste facility. Please provide the volume of drilling mud that would be generated by construction of the proposed project and may require disposal at a waste facility. It is unclear if the number on page 4.17-16 includes drilling mud.	10/30/15			
1.4.17-2	Solid Waste	p. 4.17-17 – 4.17-18	Please provide the volume of solid waste/year that would be generated during operation and maintenance of the proposed project.	10/30/15			
1.4.18	**Cumulative Analysis**						
1.4.18-1	Cumulative Analysis – Federal Projects	Table 4.18-1: Planned and Proposed Projects within one Mile of the Proposed Project	Please add the potential Marine Corps projects occurring at MCAS Miramar that could pose cumulative impacts.	10/30/15			
1.4.18-2	Cumulative Analysis – Sycamore - Penasquitos	Note 3 on Table 4.18-1	Note 3 on Table 4.18-1 discusses the CPUC environmentally preferred alternative for the Sycamore –Penasquitos Transmission Line. Provide findings of the analysis currently being undertaken to determine if both projects can be constructed or an appropriate alternative to address cumulative impacts.	10/30/15			
1.4.18-3	Pardee Parcels	p. 1-42	Public comments indicated potential single family home development planned for the Pardee parcels in Bonsall, CA. These residential developments would impact an alternative route. Address these potential cumulative projects as well as Identify other potential cumulative projects in the vicinity of other route alternatives/deviations.	10/30/15			
1.5	**Significant Impacts and Alternatives**						
1.5-1	Alternatives	Ch. 5	Provide a discussion of issues associated with the proposed route along Pomerado Road and the Sycamore Penasquitos Project's Environmentally Superior Alternatives alignment identified by the CPUC. In addition, Verify whether it would be feasible to construct both projects along	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
			Deficiency Request #1				
			Pomerado Road.				
1.5-2	Alternatives Initially Considered But Not Carried Forward	p. 5-6	Provide a map or maps of suitable scale that include all of the alternative alignments and sites initially considered but not carried forward as well as the proposed route. In addition, provide applicable GIS data layers for these routes and sites.	10/30/15			
1.5-3	Offshore Alternative	p. 5-6	Provide a discussion of the Offshore Alternative that identifies the following: 1) the beginning and end points; 2) the total length of the alternative; 3) the length of each onshore portion of the alternative - at both the north and south ends; 4) the length of offshore portion of the alternative; and, 5) any sensitive environmental features crossed by the onshore portion of the alternative. Provide a table similar to Table 5-1 that presents the quantitative estimate of impacts on the environmental features crossed by this alternative.	10/30/15			
1.5-4	Existing Line 1600 Alignment Alternatives	p. 5-8	Provide a map showing the probable locations of the numerous temporary lateral pipelines necessary to maintain service to the customers served by Line 1600 in the event one of the existing alignment alternatives is selected. Provide a table similar to Table 5-1 presenting data on the temporary laterals including the number and length of the laterals and the quantitative estimate of impacts on the environmental features crossed.	10/30/15			
1.5-5	Existing Line 1600 Alignment Alternatives	p. 5-8	Provide a map of Line 1600 that identifies the locations of constraints along the existing right-of-way. The map should also show where expansion of the existing right-of-way for a new pipeline could address each constraint and where the constraint is severe enough to require a route deviation from the existing right-of-way. Include a table similar to Table 5-1 that presents the quantitative estimate of impacts on the environmental features crossed by the expanded right-of-way and by the route deviations.	10/30/15			
1.5-6	Existing Line 1600 Alignment Alternatives	p. 5-8	Provide a copy of the Feasibility Report prepared acquiring right-of-way for a route parallel to Line 1600.	10/30/15			
1.5-7	LNG Alternatives	p. 5-13	The PEA includes an LNG alternative that would entail constructing a liquefaction facility in a highly urbanized area. Provide an LNG alternative that considers constructing an LNG facility in a more appropriate location (i.e., rural area) and include the lengths of pipeline necessary to connect the existing pipeline system to the facility.	10/30/15			
1.5-8	LNG Alternative	p. 5-13	Describe the viability of an LNG alternative that would consist of a LNG peak-shaving facility that would include LNG storage tanks supplied by truck from existing LNG plants. See also Def. Item 1-5.9.	10/30/15			
1.5-9	LNG Alternative / Storage Facilities Near Load	p. 5-13	a. Provide a thorough discussion of an alternative that would site aboveground (LNG) natural gas storage at or near one or more major natural gas generation facilities or peaker facilities. Discuss other high-demand facilities/load centers (if any) for which aboveground storage may be appropriate to address sudden changes in gas demand. b. Provide the name and location of all major natural gas generation and peaker facilities in SDG&E's service area on a map of suitable scale (e.g., Pio Pico, Carlsbad, Encina, Otay Mesa, Palomar, Escondido-Pala area, Miramar area, South Bay area, El Cajon area, Kearny Mesa area, others). Also provide the status of these facilities (e.g., operational, scheduled to close in 20XX, total MW, proposed, etc.). Identify the cutoff for the term "major" (e.g., facility groups by area above 90 MW). Include proposed facilities (if publically known) and those under construction. c. Identify all Natural Gas Generators and their capacity in MW that are seen by SDG&E/SoCalGas as high-demand users (or potential high-demand users) that are expected to put the system at risk of curtailment during peak periods. If the facilities are only proposed, already have a firm construction schedule, or already have an online date scheduled, provide this information. d. Identify natural gas generation facilities that could best accommodate aboveground natural gas storage based on available land, their overall location, and other relevant siting criteria. Address the CPUC's assumption that a few large gas containment facilities would be more desirable than many small facilities.	10/30/15			See attached two SDG&E gas generator fact sheets
1.5-10	Infrastructure Corridor Alternative	p. 5-14	The PEA describes as infeasible the alternative of siting the proposed pipeline in the existing right-of-way of Interstate-15 because of a policy conflict with Caltrans. Provide documentation of an existing policy that prohibits either Caltrans or the USDOT from permitting the proposed pipeline placement within the Interstate Highway easement.	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
			Deficiency Request #1				
1.5-11	Northern Baja Alternative	p. 5-15	The PEA states that, currently, SoCalGas/SDG&E only receive natural gas at the existing Otay Mesa receipt point from the North Baja and Baja Norte/Gasoducto Rosarito/TGN pipelines when required by a maintenance outage or in support of maintenance activities due to higher delivery costs. Explain if these high delivery costs would be reduced if SDG&E entered into a long-term agreement for firm capacity on those pipelines.	10/30/15			
1.5-12	Northern Baja Alternative	p. 5-15	The PEA states that the Northern Baja Alternative would not meet the project objectives of system reliability and resiliency or operational flexibility unless SDG&E or its customers were able to enter in to a long-term contract for the necessary capacity with all four pipeline systems (North Baja, Baja Norte, Gasoducto Rosarito, and TGN). Discuss the potential for such a long-term contract with these for pipelines.	10/30/15			
1.5-13	Northern Baja Alternative	p. 5-15	Are there any additional permits required to move gas across the international border using the Northern Baja Alternative?	10/30/15			
1.5-14	Northern Baja Alternative	Ch. 5, p. 5-15	Provide substantial evidence that supports SDG&E's claim that pipeline capacity is not available on the pipelines in Mexico that are operated by Sempra or its subsidiaries to supply sufficient natural gas to the Otay Mesa receipt point and serve as a feasible alternative to the proposed project. If SDG&E and SoCalGas do not have access to the required data, provide a contact at the parent company, Sempra, who could assist with this deficiency item.	10/30/15			
1.5-15	Northern Baja Alternative	Ch. 5, p. 5-15	Provide evidence that supports SDG&E/SoCalGas's claim that "existing capacity on the Gasoducto Rosarito pipeline "appears" to be under contract until at least 2022."	10/30/15			
1.5-16	No Project/No Action Alternative	p. 5-35	Provide an expanded description of the No Project/ No Action Alternative that includes the following: 1) a discussion of the hazards of a hydrostatic pressure test; 2) the potential for a high pressure release of test water and the effects of such a release; 3) a typical plan that pipeline companies implement when hydrostatically testing an existing pipeline near residences (e.g., are temporary evacuations or relocations necessary); and 4) a typical plan that pipeline companies implement when hydrostatically testing an existing pipeline that is in the roadway in an urban area.	10/30/15			
1.5-17	No Project Alternative	p. 5-35	The PEA states that hydrostatically testing Line 1600 would require the construction of 42 bypasses to maintain service to customers during the testing. Provide a map showing the locations of these bypasses/temporary lateral pipelines. Provide a table similar to Table 5-1 presenting data on the temporary laterals including the length of the laterals and the quantitative estimate of impacts on the environmental features crossed.	10/30/15			
1.5-18	Alternative Energy Sources	p. 5-29	Provide a description of how the predicted energy demand in the project service area could be met by alternative fuels or energy sources.	10/30/15			
1.5-19	Route Segment Alternatives	p. 5-37	Provide an expanded description of the route segment alternatives. Provide a Table similar to Table 5-1 showing the length of the preferred and alternative segments, environmental constraints, and a quantitative assessment of impacts so that the routes can be compared.	10/30/15			
1.5-20	Community Road Route Segment Alternative	p. 5-48	Provide an updated Figure 5-2 to include the Community Road Route Segment Alternative, as well as the associated GIS shapefiles.	10/30/15			
1.5-21	CEC 2008 Alternatives	Ch. 5	Provide the alignments on maps of suitable scale, brief project descriptions, and brief discussions of the merits of the following two potential alternatives to the proposed project in the attached CEC report on pg. 36: (1) a new 25-mile line (36 inch) identified by SDG&E; and (2) a new line from Moreno Station to Rainbow Station. *"In R.04-01-025, SoCalGas and SDG&E identified that the capacity of the SDG&E system could be expanded by 50 MMcfd year-round by installing 25 miles of 36-inch-diameter pipe between Rainbow Station and Escondido. A preliminary estimate of the cost of this upgrade was $115 million. In addition, it may also be possible to construct an additional pipeline between Moreno Station and Rainbow Station. This option, however, will require additional rights-of-way and would likely be more expensive than a pipeline from Rainbow Station to Escondido."*	10/30/15			See attached report CEC-600-2008-008
1.5-22	Energy Conservation (CEQA Appendix F, Section 15126.4,	Ch. 5	Provide a discussion of Significant Irreversible Environmental Changes that would be caused by the proposed project. Primary impacts and, particularly, secondary impacts (such as highway	10/30/15			

Table 1: Rainbow–San Diego (Line 3602) 36-inch Natural Gas Pipeline Project Application Deficiencies (October 30, 2015)

Def #	Resource Area / Topic	Source / PEA Page	Deficiency Item / Data Gap Question	Request Date	Reply Date	Status	Notes
Deficiency Request #1							
	Section 21100(b)(3))		improvement which provides access to a previously inaccessible area) generally commit future generations to similar uses. The discussion should also address the extent to which future energy conservation initiatives and increases in renewable energy uses may be preempted by the additional natural gas capacity that would be available in a 36-inch pipeline. Possible future adjustments to the compression system to make full use of the additional pipeline capacity from a pipeline of that diameter must be discussed.				
1.5-23	Energy Conservation (CEQA Appendix F, Section 15126.4, Section 21100(b)(3)) / Growth Inducement	Ch. 5	Growth Inducement: The potential for a substantial increase in natural gas supply must be discussed with respect to the potential for inducing future growth in residential, industrial, and other sectors. SDG&E staff and the PEA indicate that the need for additional capacity, on its own, is not sufficient justification for the proposed 36-inch diameter pipeline. Indeed, the CEC's final July 2014 gas demand outlooks report does not indicate gas demand will increase on an annual basis in the next 10 years. The demand shown is relatively flat. CEC data since the 1990s indicates that gas demand has dropped considerably through 2013 in SDG&E's service area. See Attachment 3. See also SDG&E's Gas Capacity Planning filings to the CPUC in 2014 and 2015 (attached). Because of the CEC data, which were provided to SDG&E/SoCalGas by the CPUC, the respective project objective was adjusted between the draft and final PEA submittals to indicate that the increase of 200 MMcfd would be a product of a new 36-inch pipeline's installation and that the specific increase of 200 MMcfd is not in itself a project objective. The draft objective was stated as, "Increase the capacity of SDG&E's natural gas transmission system by approximately 200 MMcfd. The final objective now reads, "Simultaneously increase the transmission capacity of the Gas System in San Diego County by approximately 200 million cubic feet per day (MMcfd) as a result of the PSEP replacement line being 36 inches in diameter." One justification for such a large, new gas pipeline in terms of increased capacity explained by SDG&E staff is the ability to pack the line and store natural gas. This explanation, however, fails to take into account possible future adjustments to the compression system to make full use of the additional pipeline capacity rather than for simply packing the line.	10/30/15			See Attachment 3 and SDG&E/SoCalGas Gas Capacity Planning Reports (April 2014, October 2014, April 2015, October 2015)

From: Navin, Neil [mailto:NNavin@semprautilities.com]
Sent: Tuesday, September 29, 2015 9:23 PM
To: Peterson, Robert
Cc: Collins-Burgard, Beth; Armen Keochekian; lkahal@insigniaenv.com; de Llanos, Estela; HSteenberge@BHFS.com; Ith, Boramy; Martin, Erica L; Salazar, Jeff; Marelli, Gwen; Musich, Beth; Hovsepian, Melissa A; Phan, Thanh; Bisi, David; Blessent, Beverly; de Llanos, Estela
Subject: Rainbow-San Diego 36-in Gas Pipeline Project (CPCN filing pending 9/30/15)

Rob,

In response to your question regarding gas transmission capacity with the introduction of the replacement line, please find attached the table and some clarifying notes. We look forward to addressing this further in a future conversation with our capacity & planning staff.

Table 1 (Version A). Current and Proposed Capacities of SDG&E's North-to-South Natural Gas Transmission System (MMcfd)

	Current Capacity	Proposed Capacity with Line 1600 De-rated to Lower Pressure and Line 3602 in Operation
Line 1026	Dist. Service – N/A	Distribution Service Pressure – N/A
Line 1600 (16 inch)	100	Distribution Service Pressure – N/A
Line 3010 (30 inch)	530	340
Line 3602 (36 inch)	n/a	490
Combined	**630 MMcfd**	**830 MMcfd**

A few things to note:

- These are nominal pipeline capacities. The actual flow rate for each pipeline is a function of both the size and location of the demand on the SDG&E system, and will vary from these figures even at a level of demand equal to the system capacity.
- The system capacity is a hard limit. This is function of the location and size of customer demand on the SDG&E system, and the maximum and minimum operating pressures necessary to maintain system integrity. The capacity of the system or of any individual pipeline cannot exceed this hard limit unless the boundary conditions (i.e. maximum and minimum pressures) are changed, or there is a significant change in the location of demand on the SDG&E system.
- Each pipeline individually has a larger capacity alone than when operating as part of the system. There is no "lost" capacity on L3010 if L3602 is installed.
- 12-inch Line 1026 has been operating at distribution-level pressures for some time now, and does not contribute to the SDG&E system capacity in any meaningful way. Similarly, Line 1600, when derated to operate at distribution-level pressures, will also not contribute to the SDG&E system capacity in any meaningful way.

Best regards,

Neil

Complete Table 2-1.

Table 2-1: Lines 3010 and 1600 Recorded and Forecast Peak Demand (Combine) from 2004 through 2025 in MMcfd

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Winter (recorded)	630?										
Summer (recorded)	590?										
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Winter (forecast)											
Summer (forecast)											

Past email with this request:

From: Peterson, Robert
Sent: Friday, July 24, 2015 4:51 PM
To: de Llanos, Estela
Cc: Anne Marie McGraw; Blessent, Beverly; Navin, Neil; Farrell, Peggy; Karpowicz, Ron; Salazar, Jeff; Borak, Mary Jo
Subject: RAIN 3602: Comments Set 1 (Pre-File PEA Chapter 2: Project Purpose and Need/Project Objectives)

Estela and Team,

Instead of waiting to send a big package of comments, I decided to send this off today. My next series of comments will address the project description and specific alternatives.

Pre-File PEA Chapter 2: Project Purpose and Need/Project Objectives
The PEA does not provide sufficient justification for the proposed capacity increase of 200 MMcfd. Further data will be necessary to ensure that a reasonable range of alternatives can be i dentified and to determine whether each alternative meets the project's basic objectives. Further data will also be needed to sufficiently document the project's underlying purpose.

As noted in the CEC's California Energy Demand 2014-2024 Final Forecast (CEC 2014, p. 69, Table 20), natural gas demand in SDG&E's service territory has reduced by more than 200 MM therms since 1990 (about 28 percent) and is expected to further reduce through this year. The following table or similar should be updated based on 2015 historical values for inclusion in the PEA. A discussion should also be provided.

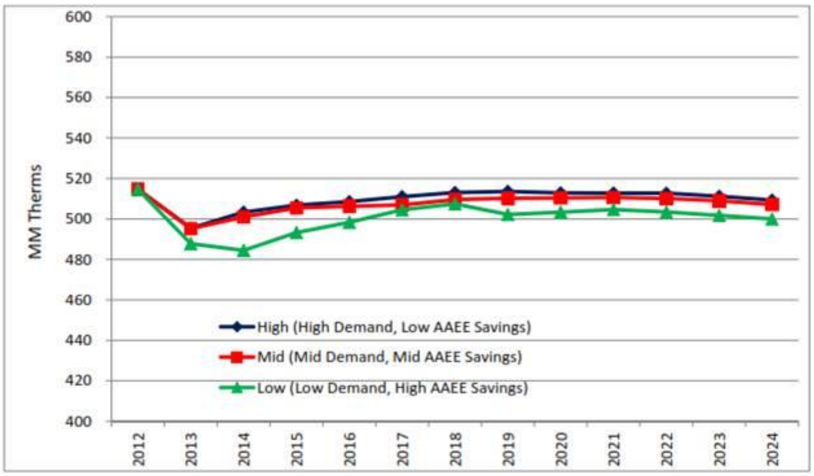
Table 20: SDG&E Baseline Natural Gas Forecast Comparison

	Consumption (MM Therms)			
	CED 2011 Mid Case	*CED 2013 Final High Energy Demand*	*CED 2013 Final Mid Energy Demand*	*CED 2013 Final Low Energy Demand*
1990	717	717	717	717
2000	565	565	565	565
2012	580	515	515	515
2015	609	508	507	495
2020	665	524	524	522
2024	--	530	535	541
	Average Annual Growth Rates			
1990-2000	-2.35%	-2.35%	-2.35%	-2.35%
2000-2012	0.22%	-0.78%	-0.78%	-0.78%
2012-2015	1.62%	-0.43%	-0.51%	-1.28%
2012-2022	1.69%	0.26%	0.31%	0.34%
2012-2024	--	0.24%	0.32%	0.41%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

With the inclusion of Additional Achievable Energy Efficiency (AAEE) savings, the CEC does not forecast that natural gas demand will exceed 2012 levels in the next 10 years (CEC 2014, p. 75, Figure 36). Demand would equate to between -0.09 percent and -0.24 percent through 2024. The following chart or similar should be updated based on 2015 data for inclusion in the PEA. A discussion should be provided.

Figure 36: Adjusted Demand Scenarios for Natural Gas, SDG&E Service Territory



Source: California Energy Commission, Demand Analysis Office, 2013

In addition, the following table or similar will be necessary to provide sufficient justification for the proposed capacity increase of 200 MMcfd and to identify and evaluate a reasonable range of alternatives.

Lines 3010 and 1600 Recorded and Forecast Peak Demand (Combined) from 2004 through 2025 in MMcfd

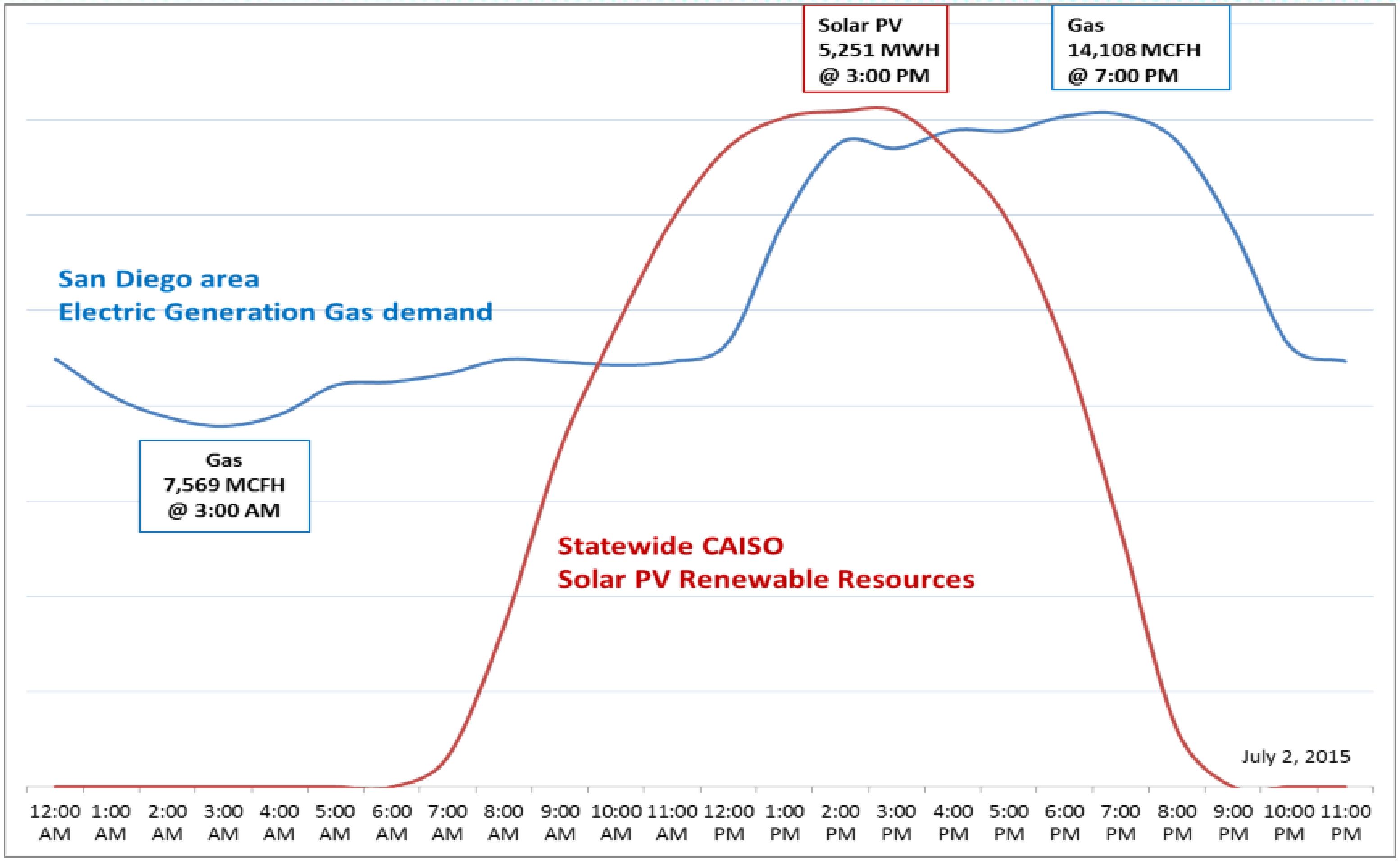
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Winter (recorded)	630?										
Summer (recorded)	590?										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Winter (forecast)											
Summer (forecast)											

Notes: Identify SDG&E's assumptions required to complete this table and describe the relationship between the data
applied to this table and the data reported to the CEC for its latest annual California Energy Demand forecast report.

Rob Peterson | Project Manager | Infrastructure Permitting and CEQA, Energy Division | California Public Utilities Commission | 505 Van Ness Ave, San Francisco 94102 | 415/703-2820

Solar and Gas Demand on July 2, 2015

SDGE
A Sempra Energy utility



A Sempra Energy utility®

Joff Morales
Regulatory Affairs
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 858-650-4098
JMorales@semprautilities.com

October 23, 2015

PUG 100
I.00-11-002

Mr. Edward Randolph
Director – Energy Division
California Public Utilities Commission
505 Van Ness Avenue, 4-A
San Francisco, CA 94102

Re: Gas Capacity Planning and Demand Forecast Semi-Annual Report

Dear Mr. Randolph,

Pursuant to California Public Utilities Commission Decision 02-11-073 in the Gas Transmission OII (I.00-11-002), SDG&E hereby submits the attached semi-annual report on its gas system capacity planning and demand forecasts.

If you have any questions, please contact Joff Morales at (858) 650-4098.

Sincerely,

Joff Morales
Regulatory Affairs

Enclosures

cc: Greg Reisinger, Energy Division
Richard Myers, Energy Division

SAN DIEGO GAS & ELECTRIC COMPANY
GAS CAPACITY PLANNING AND DEMAND FORECAST
SEMI-ANNUAL REPORT

Pursuant to Ordering Paragraph 9 of California Public Utilities Commission (CPUC or Commission) Decision No. (D.) 02-11-073[1] (issued November 21, 2002 in I.00-11-002), San Diego Gas & Electric Company (SDG&E) hereby submits its semi-annual report on its gas system capacity planning and demand forecasts.

This report addresses the adequacy of the SDG&E gas transmission system to meet the forecast of incremental gas demand, and whether that growth in gas demand would indicate the need for SDG&E to add incremental gas transmission capacity, within the confines of the process adopted by the Commission in D.02-11-073 (i.e., using the firm service requests obtained during regular capacity open seasons, along with traditional demand forecasts, to signal whether additional capacity is needed).

I. EXECUTIVE SUMMARY

SDG&E system capacity continues to meet the 1-in-35 year peak day and 1-in-10 year cold day design condition forecasts for core and firm noncore customers, respectively, through the 2035/36 operating season, assuming all transmission assets are in service. However, connected load in San Diego still far exceeds both these forecast figures and existing SDG&E system capacity, and SDG&E may need to curtail interruptible service as necessary to maintain firm service obligations. Moreover, if a substantial percentage of SDG&E noncore customers currently receiving interruptible service would seek to switch to firm service, SDG&E will probably not have enough firm capacity to meet all such requests.

Please take note that this assessment regarding the capability to serve core and firm noncore customers is an evaluation of the available pipeline capacity in San Diego only. Curtailments of firm noncore service are certainly possible, and in fact have recently happened, as a result of lack of supply delivered to the SDG&E system. Accordingly, Southern California Gas Company (SoCalGas) and SDG&E no longer believe that the open season process is adequate in and of itself to signal the need to expand the SDG&E system capacity. Furthermore, SoCalGas and SDG&E have filed to eliminate the firm and interruptible tariff rate distinctions as part of their curtailment rule revision Application (A.) 15-06-020.

II. CURRENT SDG&E SYSTEM CAPACITY

Given the current physical location of customers on the San Diego system, SDG&E has the capacity to serve 630 million cubic feet per day (MMcfd) of customer demand in the winter operating season and 590 MMcfd of customer demand in the summer operating

[1] Titled “Opinion on Adequacy of Southern California Gas Company’s and San Diego Gas and Electric Company’s Gas Transmission Systems to Serve the Present and Future Needs of Core and Noncore Gas Customers.”

season. If core demand in the Rainbow Corridor continues to grow at its current pace, without system improvements or other enhancements, SDG&E system capacity may decline by the 2035/36 operating year to 620 MMcfd in the winter and 580 MMcfd in the summer.

III. CAPACITY OPEN SEASONS

In D.02-11-073, the Commission ordered SDG&E to conduct open seasons for the allocation of firm transportation capacity on its gas transmission system. In D.06-09-039, the Commission authorized SDG&E and SoCalGas to conduct capacity open seasons in any areas of their local transmission systems that are constrained or are expected to be constrained. Pursuant to these orders, in May 2015 SDG&E conducted a capacity open season for the terms June 1, 2015, through May 31, 2017 (smaller customers) and June 1, 2015, through May 31, 2020 (larger customers) concurrent with SoCalGas' open season in the Rainbow Corridor.

D.06-09-039 further authorized SDG&E and SoCalGas to require longer-term commitments in the open seasons for large customers. Pursuant to this authorization, SDG&E and SoCalGas defined their open season terms for large customers as the earlier of (1) two years from the date that any associated facilities necessary for capacity improvements are placed into service; or (2) five years from the customer's sign-up date. The open seasons also provided that if the results do not require prorationing of capacity and the Commission agrees that no facilities are needed, large noncore customer commitments will have a term of two years. No prorationing of capacity was required for either 2015 open season, and in August 2015 the Commission approved our open season advice filings[2] which explained that, based on the open season results, no facility improvements were needed and requested approval to reduce the term to two years for large noncore customers.

IV. DEMAND FORECAST AND CAPACITY ASSESSMENT

In D.02-11-073, the Commission affirmed a 1-in-35 year cold day condition as the design criteria for core service, and established a new 1-in-10 year cold day design criteria for noncore firm service. These standards were reaffirmed in D.06-09-039. Table 1 shows SDG&E's long-term demand forecast for the 1-in-35 year and 1-in-10 year cold day demand conditions.

[2] SoCalGas Advice Letter 4829 and SDG&E Advice Letter 2397-G.

Table 1
SDG&E Long-Term Demand Forecast[3]

	1-in-35 Year Cold Day Demand (MMCFD)				1-in-10 Year Cold Day Demand [a/] (MMCFD)			
Operating Year [b/]	Core	Noncore C&I	EG	Total	Core	Noncore C&I	EG	Total
2015/16	366	0	0	366	347	61	199	607
2016/17	370	0	0	370	350	62	165	577
2017/18	372	0	0	372	352	62	168	582
2018/19	373	0	0	373	353	63	173	589
2019/20	374	0	0	374	353	63	173	589
2020/21	373	0	0	373	352	63	175	590
2021/22	373	0	0	373	353	62	175	590
2022/23	374	0	0	374	353	62	175	590
2023/24	374	0	0	374	353	62	175	590
2024/25	374	0	0	374	354	62	174	589
2025/26	376	0	0	376	356	61	174	591
2030/31	389	0	0	389	368	61	174	603
2035/36	404	0	0	404	382	61	174	617

a/ The gas demand forecasts for noncore commercial & industrial (C&I) and electric generation (EG) customer classes do not distinguish between firm and interruptible noncore service. Thus, for the purposes of this assessment, SDG&E assumed that all future peak C&I and EG loads elected firm noncore service.
b/ April through December, along with the following January through March.

Assuming the Rainbow Corridor demand continues to grow at its current pace, the SDG&E winter system capacity would fall from its current level of 630 MMcfd to 620 MMcfd by the 2035/36 operating season. As shown in Table 1, this is sufficient capacity to meet the 1-in-35 year peak day design standard and the 1-in-10 year cold day design standard through the forecast period. However, as noted above and in our prior semi-annual capacity planning reports, even though SDG&E has capacity to serve forecasted core and *firm* noncore 1-in-10 year cold day demand, connected load in San Diego still far exceeds these forecast figures and the existing SDG&E system capacity (currently 1.3 billion cubic feet per day of demand under a 1-in-10 year cold day conditon for the core with connected load for the noncore). This is because there is substantial interruptible noncore load on the SDG&E system, particularly EG load. Despite predicted declines in natural gas demand on an annual basis, SDG&E and SoCalGas are not forecasting declines in our peak day design standard demand shown in Table 1, which looks at daily demand rather than annual demand, and have experienced more sudden changes within an operating day when the gas system is called upon to replace losses from other sources of electricity, including regularly-occurring losses of renewable sources. Although such conditions are not typically considered in the development of formal demand forecasts, these conditions frequently occur on an

[3] Derived from data developed for the 2016 Triennial Cost Allocation Proceeding (TCAP), A.14-12-017.

operational basis, and are anticipated to become more common as weather conditions and the use of natural gas to support renewable electric generation continue to change. Accordingly, it is entirely possible that total *firm* and *interruptible* noncore demand in San Diego may exceed the system capacity on a day warmer than the 1-in-10 year cold day, and SDG&E may need to curtail interruptible service as necessary to maintain firm service obligations. While this situation is exacerbated by the San Onofre Nuclear Generating Station (SONGS) retirement and increasing electric generation in the San Diego region, it is not new; SDG&E has never represented that it has sufficient capacity to serve all interruptible demand in San Diego without curtailment.

Additionally, as SoCalGas and SDG&E continue to implement their pipeline safety programs, it may be necessary to temporarily reduce the operating pressure in our pipelines (as is the case right now with the southern portion of Line 1600). Furthermore, due to permitting and other construction issues necessary to repair a pipeline, the pipeline's operating pressure may be reduced for an extended period of time. While SoCalGas and SDG&E will continue our practice of minimizing any resulting impact to our customers, it may be necessary to curtail some noncore customers (interrruptible and firm) in order to maintain system integrity.

V. STATUS OF REQUESTS FOR FIRM SERVICE

SDG&E was able to satisfy all firm service requests during its last open season. However, firm service requests came within 68 MMcfd of exceeding available firm capacity in the winter operating season. As reported in AL 2397-G:

> Available capacity on the Rainbow Corridor and the SDG&E system is dependent upon the location of the customer demand on both systems. Based on the level of core demand in the Rainbow Corridor and on the SDG&E system, the current capacity of the SDG&E/Rainbow Corridor system is 760 MMcfd in the winter operating season and 740 MMcfd in the summer. This capacity was made available to both SoCalGas Rainbow Corridor customers and SDG&E customers during the Open Season. The firm service awards result in peak firm demand (core and noncore) of 672 MMcfd in the winter (551 MMcfd on the SDG&E system, 121 MMcfd in the Rainbow Corridor) and 450 MMcfd in the summer (373 MMcfd on the SDG&E system, 77 MMcfd in the Rainbow Corridor), resulting in excess capacity in both operating seasons. [4]

SoCalGas and SDG&E do not foresee being able to offer more firm capacity during the next open season than 740 MMcfd in the winter operating season and 680 MMcfd in the summer offered previously.

Since the 2015 SDG&E Pipeline Capacity Open Season, three customers have each signed an interruptible noncore service contract and one customer has signed a total of 14 new interruptible noncore service contracts. The 17 additional interruptible noncore service contracts total 598 thousand cubic feet per day (MCFD).

[4] AL 2397-G, page 2.

VI. POTENTIAL CAPACITY IMPROVEMENTS

In D.11-06-017, SoCalGas and SDG&E were ordered to pressure test or replace those pipelines that lack sufficient documentation of pressure testing to meet the safety requirements set forth in the Decision. In compliance with that order, on September 30, 2015, SDG&E and SoCalGas filed A.15-09-013 for a Certificate of Public Convenience and NecessityNessisty to construct a pipeline (the “Pipeline Safety & Reliability Project”) to replace Line 1600. The Pipeline Safety & Reliability Project is needed to meet the following objectives: (1) enable compliance with the Commission-approved Pipeline Safety Enhancement Plan (PSEP) by replacing Line 1600 with a new gas transmission pipeline as soon as is practicable; (2) simultaneously improve the reliability and resiliency of the gas system by replacing Line 1600 with a 36-inch-diameter gas transmission pipeline so that core and noncore customers will continue to receive gas service in San Diego in the event of a planned or unplanned service reduction or outage of the existing 30-inch-diameter Line 3010 or the Moreno Compressor Station; and (3) simultaneously increase the transmission capacity of the gas system in San Diego County by approximately 200 MMcfd as a result of the PSEP replacement line being 36 inches in diameter so that SDG&E and SoCalGas can reliably manage the fluctuating peak demand of core and noncore customers. The new line would provide incremental pipeline capacity that would give flexibility to operate the SDG&E system by expanding the options available to handle stress conditions on a daily and hourly basis that put system integrity and customer service at risk.

SAN DIEGO GAS & ELECTRIC ELECTRIC GENERATION FACT SHEET

A Sempra Energy utility®

OVERVIEW

San Diego Gas & Electric (SDG&E) supplies customers with electricity generated both locally and outside of the utility's service territory, with local facilities currently capable of generating a total of approximately 3,100 megawatts (MW) of power. SDG&E owns and contracts with generation facilities both within and outside the service territory, and power is also produced in local facilities that are non-utility owned. Local generation is important for local power supply needs due to the voltage support it provides that keeps the electric system running smoothly.

LOCAL GENERATION RESOURCES*

Palomar Energy Center	566 MW
Otay Mesa Energy Center	604 MW
Encina Power Station	964 MW
Peakers (South Bay area)	175 MW
Peakers (El Cajon area)	109 MW
Peakers (Escondido-Pala area)	197 MW
Peakers (Miramar area)	132 MW
Peakers (Kearney Mesa area)	136 MW
Qualifying Facilities**	140 MW
Renewables/Pumped Hydro***	94 MW
Total	3,117 MW

SDG&E-OWNED FACILITIES

Palomar Energy Center
Peakers (Miramar I & II, Cuyamaca)
Desert Star Energy Center (located in Nevada)

GENERATION BY TYPE

SDG&E's 2013 power mix included the following energy resources:

- Renewable: 24%****
  - Biomass & waste: 3.0%
  - Geothermal: 2.0%
  - Small hydroelectric: 0.0%
  - Solar: 4.0%
  - Wind: 15.0%
- Coal: 3.0%
- Large hydroelectric: 0.0%
- Natural gas: 67.0%
- Nuclear: 0.0%
- Oil: 0.0%
- Unspecified: 6.0% (electricity from transactions that are not traceable to specific generation sources)

MEDIA CONTACT

SDG&E Media Relations
877-866-2066 (24 Hours)

*Capacity values are based on current California ISO Net Qualified Capacity Rating that can change from year to year.
**Qualifying facilities are non-utility small alternative, natural gas and renewable sources of energy, including co-generators and other sources.
***Includes Lake Hodges, Kumeyaay and Borrego Solar
****This represents physical power purchased to support SDG&E's system load.

###

9/29/2014

PEAKER PLANTS
FACT SHEET

A Sempra Energy utility®

OVERVIEW

Peaker plants are small power units that can reach full generating capacity within 10 to 15 minutes to meet immediate demand on the grid. There are 24 natural gas-fired peaker units at 12 locations within SDG&E's service area, with three peakers that are owned by SDG&E, known as Miramar Energy Facility (Miramar I and Miramar II) and Cuyamaca Peak Energy Plant. Peakers are typically called on when demand for power is highest, such as a hot summer day, or at times when loads are changing rapidly.

LOCAL PEAKER FACILITIES

Facility	Total MW	Location
Cal Peak - Border	48	Otay Mesa
Cal Peak - Enterprise	48	Escondido area
El Cajon GT	16	El Cajon
Orange Grove (2 units)	100	Pala area
Kearny (9 units)	136	Kearny Mesa
Larkspur (2 units)	92	South Bay area
Wellhead – Chula Vista	35	Chula Vista
Wellhead – Escondido	49	Escondido
Miramar (2 units)	36	Miramar area
Cuyamaca Peak Energy Plant	45	El Cajon
Miramar Energy Facility (2 units: Miramar I & Miramar II)	96	Miramar area
Wellhead El Cajon	48	El Cajon
TOTAL	**749 MW**	

SDG&E-OWNED PEAKERS

Miramar Energy Facility (Miramar I & Miramar II)

The Miramar Energy Facility produces 96 MW of power and is located in the Miramar area of San Diego. The plant consists of two turbine-generators known as Miramar I and Miramar II, which began service in 2005 and 2009 respectively. Each unit can produce 48 MW.

Cuyamaca Peak Energy Plant

Cuyamaca Peak Energy Plant is a 45-MW single unit simple-cycle peaking power plant. On Jan. 1, 2012, SDG&E purchased the natural gas-fired Cuyamaca Peak Energy Plant (formerly CalPeak El Cajon Energy Facility) located in El Cajon, Calif., from CalPeak Power-El Cajon LLC.

MEDIA CONTACT

SDG&E Media Relations
877-866-2066 (24 Hours)

###

CURRENT STATUS, PLANS, AND CONSTRAINTS RELATED TO EXPANSION OF NATURAL GAS-FIRED POWER PLANTS, PIPELINES AND BULK ELECTRIC TRANSMISSION IN THE CALIFORNIA/MEXICO BORDER REGION

CONSULTANT REPORT

Prepared For:
California Energy Commission

Prepared By:
KEMA, Inc.
Bates-White, LLC

AUGUST 2008
CEC-600-2008-008

Prepared By:
KEMA Inc.
Karin Corfee, Project Manager
David Korinek, Task Manager

Bates-White, LLC
Nicolas Puga, Consultant
Contract No: 600-05-011

Prepared For:
California Energy Commission

Alan Argentine
Contract Manager

Albert Estrada
Program Manager

John Sugar
Office Manager
SPECIAL PROJECTS OFFICE

Michael Smith
Deputy Director
FUELS AND TRANSPORTATION DIVISION

Melissa Jones
Executive Director

Please cite this report as follows:

Korinek, David; DeMetro, James; Puga, Nicolas. *Current Status, Plans, and Constraints Related to Expansion of Natural Gas-Fired Power Plants, Pipelines and Bulk Electric Transmission in the California/Mexico Border Region*. California Energy Commission. Publication number: CEC-600-2008-008.

Table of Contents

List of Figures

List of Tables

Abstract

The report describes the current status and expansion plans for gas-fired power plants, bulk electric transmission, and natural gas transmission pipelines in the California/Mexico border region. Existing and forecasted supply-demand balance for both electric and gas capacity are described for specified zones on both sides of the border, along with flow constraints between the zones. Natural gas flow constraints and pipeline projects discussed in the report include the path between Erhenberg/Blythe and Baja California, pipeline capacity across northern Baja California, the delivery constraint south of Moreno in the Southern California Gas system, and pipeline capacity between San Diego Gas & Electric (SDG&E) and Baja at Otay Mesa. Impacts of Sempra Energy's Costa Azul LNG terminal project on pipeline constraints is also described. A description of electric transmission constraints and proposed projects is provided including Western Electricity Coordinating Council (WECC) Path 45 between Baja California and the California Independent System Operator (California ISO). Also included is the existing and proposed electric transmission capacity from the Imperial Valley to the west and north, and the impact of the proposed Sunrise Powerlink and Green Path North transmission projects.

Keywords: Power plants, gas-fired generation, electric transmission, natural gas transmission, pipelines, demand forecasts, supply forecasts, LNG terminals, California/Mexico border region, Baja California, Southern California, electric infrastructure expansion, natural gas infrastructure expansion, pipeline precedent agreements

Executive Summary

This report addresses existing energy (gas and electric) infrastructure, expansion plans, and growth projections in the California/Mexico Border region. This investigation was initiated as a result of the *2005 Integrated Energy Policy Report* (IEPR). In conjunction with IEPR, the California Energy Commission sponsored an introductory report on energy infrastructure, demand, and supply in the California/Mexico border region.[1] The IEPR highlighted the potential for significant growth in demand and the need for additional energy resources in the border region, in both the gas and electric sectors, and recommended that the State of California work to establish a cross-border bi-national energy planning and development effort.

To facilitate bi-national dialogue regarding energy infrastructure in the border region, the Energy Commission commissioned an expanded study of the region in 2007 and selected KEMA Incorporated as the lead consultant for this work. Initially, KEMA examined the potential for development of wind renewable energy resources in northern Baja California and the export of these resources to California. The results of this analysis were provided in an earlier report. [2] A subsequent report will identify and compare possible longer-term scenarios for energy infrastructure development in Baja California, Southeastern California, and the San Diego area. This series of reports may provide a common framework through which regulators, utilities, energy resource developers, and other stakeholders can examine infrastructure needs and options. The reports may also assist policy makers and regulators in both Mexico and California to implement policies and strategies that will stimulate the type of infrastructure additions that offer the greatest benefits to the border region as a whole.

---

[1] *Energy Supply and Demand Assessment for the Border Region*, California Energy Commission CEC-600-2005-023, May 2005.

[2] *Challenges and Opportunities to Deliver Renewable Energy from Baja California Norte to California*, Consultant Report, California Energy Commission, CEC-600-2008-004, June 2008.

CHAPTER 1: Demand-Resource Zones in the California/Mexico Border Region

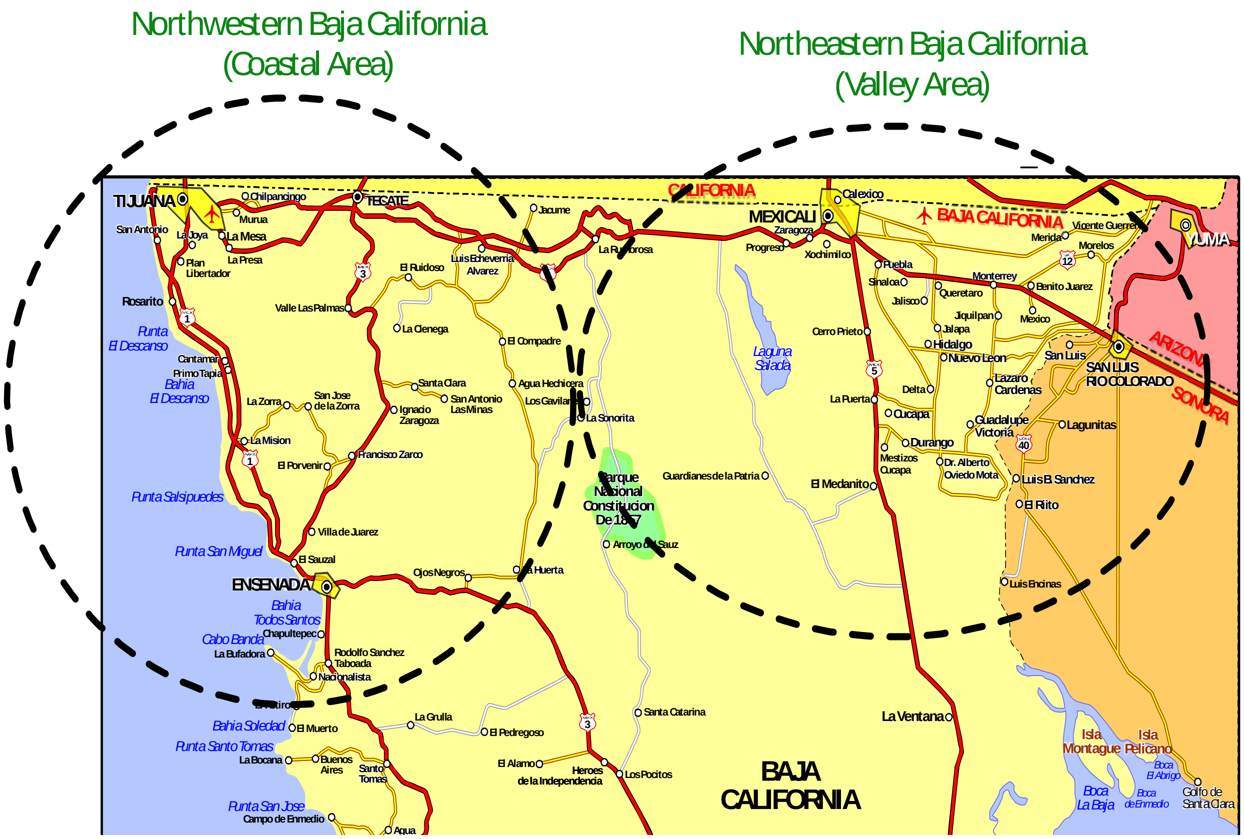
The Baja California Peninsula encompasses two separate sovereign Mexican states: Baja California (the northernmost portion of Baja) and Baja California Sur. Comisión Federal de Electricidad's (CFE's) Baja California (BC) electric control area serves the state of Baja California, the northernmost of the two. CFE's Baja California Sur electric system is electrically isolated from the BC system and is outside the scope of the current investigation.

For this report, the border region was separated into the following four zones: Southeastern California, San Diego, Northwestern Baja California, and Northeastern Baja California. These zones are used for both the electricity and natural gas assessments. The boundaries of each zone are as follows:

- Southeastern California. The zone overlays Imperial County, which is bounded on the west by San Diego County, on the south by Northeastern Baja California, on the east by the Colorado River and on the north by Riverside County. Retail electric service in the zone is provided by Imperial Irrigation District (IID). Retail gas service is provided by Southern California Gas Company, a subdivision of Sempra Utilities.
- San Diego. The zone is the service area of San Diego Gas & Electric (SDG&E), which includes San Diego County and roughly the southern third of Orange County. The zone is bounded on the south by western Baja California del Norte, on the east by Imperial County, and on the north by the electric service area of Southern California Edison (SCE).
- Northwestern Baja California. The zone covers roughly the western half of CFE's Baja California del Norte control area, typically referred to as CFE's Coastal System. It includes the Tijuana metropolitan area, as well as Ensenada, Rosarito Beach, Puerto Nuevo and Tecate. The zone is bounded on the north by the San Diego Zone.
- Northeastern Baja California. The zone covers roughly the eastern half of CFE's Baja California control area, typically referred to as CFE's Valley System. It includes the Mexicali metropolitan area and extends south to the San Felipe area. The zone is bounded on the north by the Southeastern California Zone.

CFE's BC electric power system serves two distinct geographic areas with distinct demand patterns driven by customer demographics and different climates as illustrated in Figure 1.

Figure 1: Baja California Supply and Demand Zones



Source: AdvantageMexico.com

The Northwestern BC Zone, or Coastal Area, is located west of the Juarez Mountains and encompasses the Tijuana-Rosarito metropolitan area and the cities of Ensenada and Tecate. The area enjoys the cooling effect of the Pacific Ocean breezes. The Northeastern Zone, or Valley Area, lies to the west of the Juarez Mountains and has a desert-like climate with very high summer temperatures and low humidity, which drive the demand for electricity for air conditioning and irrigation.

CHAPTER 2:
Electricity Supply Demand Balance by Zone

This section provides a zone-by-zone assessment of the current and projected electricity supply-demand balance for the Border region. The current and future year forecasts go through 2015-2017 timeframe, depending on the extent that forecast data is available in the later years. The resource data includes both utility-owned resources and independently owned resources. For the Southeastern California Zone adjustments are made in the tabulation of resources to net out the long-term firm export contracts from Imperial Irrigation District to SCE.

Only peak demand conditions and firm resource capacity are reflected in Tables 1-4. Firm resources include existing and planned geothermal generation in Baja, as well as solar generation projects currently under development in the Imperial Valley. Since wind resources cannot be scheduled to run at peak, they are not shown in these tables. However, projections of wind energy potential in northern Baja California are discussed in *Challenges and Opportunities to Deliver Renewable Energy From Baja California Norte to California*, California Energy Commission Publication No. CEC-600-2008-004. Additional information on renewable generation in BC is provided in Appendix A.

San Diego Zone Supply and Demand

Historically, the San Diego Zone has been resource deficient, and this appears unlikely to change in the planning horizon. Two approaches are used to tabulate the San Diego demand-resource balance. In Table 1, only those resources physically located within the zone are included. In Table 2, SDG&E's import capability is included in the resource category. This comparison demonstrates the extent to which the zone is dependent on imports to serve its peak demand. It should be noted that the resource (capacity) data in these two tables is SDG&E filed forecast data, which excluded intermittent renewable resources and other proposed resource additions listed in the California ISO interconnection queue but not yet considered firm capacity plans at the time of the forecast.

As shown, the San Diego Zone has a significant resource deficiency based on a straightforward comparison of peak demand versus resources located in the zone. This deficiency is compounded by the retirement of the Southbay Generating Plant, which SDG&E anticipates will occur in November 2009 under terms of the plant's property lease agreement.[3] Retiring the plant will cause a 702 megawatt (MW) reduction for the San Diego Zone. Fortunately, this will

[3] San Diego Gas & Electric rebuttal testimony, California Public Utilities Commission Sunrise Powerlink Proceeding, A.06-08-010, June 2007 (Linda Brown, pp. 11:9-18).

be offset to a large extent by the addition of new generation at Otay Mesa and Lake Hodges scheduled to come on-line in 2008.

Table 1: Electric Supply-Demand Balance (San Diego Zone) (Excluding Import Capability)

Plant Name	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Net Generating Capacity [MW]										
In Operation /1	2,938										
Retirements											
South Bay				-702							
New Entrants											
Otay Mesa CC		561									
Lake Hodges Hydro		40									
Total Capacity	2,938	3,539	3,539	2,837	2,837	2,837	2,837	2,837	2,837	2,837	
Peak Demand (90/10)	4,742	4,849	4,947	5,038	5,129	5,223	5,316	5,413	5,513	5,604	
Resource Margin	-38%	-27%	-28%	-44%	-45%	-46%	-47%	-48%	-49%	-49%	

/1 Includes Encina, Southbay, Palomar Energy Project and various peaker plants.

Source: CPUC A.05-12-014, Supplement to Application for the Sunrise Powerlink, Dec. 14, 2005

Another perspective for evaluating the electric supply-demand balance of the San Diego Zone is provided by including firm import capacity on the resource side of the equation as shown in Table 2. In fact, SDG&E uses this approach for the purpose of determining its "reliability requirements" (local resource needs vs. import capability). As shown in Table 2, SDG&E also takes into account the California ISO's "G-1, N-1" criterion in calculating its "reliability margin."[5] Due to these differences, the final row of Table 2 ("Reliability Margin") cannot be compared directly to the "Resource Margin" row(s) in the other Electric Supply-Demand Balance tables presented in this report.

[5] California Independent System Operator's "G-1, N-1" reliability planning criteria stipulates that San Diego Gas & Electric must be able to serve its 1-in-10-year peak demand forecast during the loss of both its largest internal generating resource and the worst case transmission import facility outage.

Table 2: Adjusted Supply-Demand Balance (San Diego Zone)
(Including Imports and California ISO "G-1" Requirement)

Plant Name	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Net Generating Capacity [MW]										
In Operation	2,938										
Retirements											
South Bay				-702							
New Entrants											
Otay Mesa CC		561									
Lake Hodges Hydro		40									
Firm Import Capacity											
Existing SIL /1	2,500										
Sunrise Powerlink				1,000							
Reduction for California ISO "G-1"											
Palomar Energy Proj CC /2	-541										
Otay Mesa CC /3		-20									
Total Capacity	4,897	5,478	5,478	5,776	5,776	5,776	5,776	5,776	5,776	5,776	
Peak Demand (90/10)	4,742	4,849	4,947	5,038	5,129	5,223	5,316	5,413	5,513	5,604	
Reliability Margin /4	3%	13%	11%	15%	13%	11%	9%	7%	5%	3%	

/1 SDG&E's Simultaneous Import Limit ("SIL") represents the maximum import capability that will meet NERC/WECC criteria for an outage of SWPL.
/2 California ISO "G-1" criteria for combined-cycle plants assumes outage of the entire facility.
/3 Otay Mesa plant capacity is 20 MW larger than Palomar and thereby increases the "G-1" outage.
/4 California ISO reliability planning criteria requires that SDG&E serve its full 90/10 load forecast during an outage of the largest power plant "G-1" in its system.

Source: SDG&E Application A.05-12-014, *Sunrise Powerlink Transmission Project Purpose & Need*, Vol. 2, pp. III-ii and III-4.

Southeastern California Zone Supply and Demand

The supply-demand balance for Southeastern California is shown in Table 3. It is important to note that this tabulation includes merchant generation connected at SDG&E's Imperial Valley (IV) Substation, which is physically within the Southeastern California Zone as defined for this study. Conversely, even though SDG&E owns the IV Substation, the resources connected there are not included in Tables 1 or 2 since they are neither within the San Diego Zone nor contracted to SDG&E.

Table 3: Electric Supply-Demand Balance (Southeastern California Zone)

Resource Description	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Net Generating Capacity [MW]										
In Operation /1	2,650										
Retirements/Removals /2											
El Centro Unit #3				-42							
New Entrants											
RFP #484 Products	150	90		117		-100					-50
Sterling Energy Systems /3				300		300					
Less Firm Exports to SCE	-552										
Total Southeast CA Capacity	2,248	2,338	2,338	2,713	2,713	2,913	2,913	2,913	2,913	2,913	2,863
Gross Peak Demand (IID)	1,025	1,078	1,123	1,166	1,209	1,253	1,300	1,348	1,397	1,449	1,503
Capacity Reserve Margin /4	119%	117%	108%	133%	124%	132%	124%	116%	109%	101%	90%

/1 Includes IID firm resources & contracts (978 MW), Termoelectrico de Mexicali (650 MW), Baja California Power (470MW) & geothermal gen (552 MW).
/2 El Centro Unit 3 will be removed from service in order to be reconfigured as a combined-cycle plant.
/3 SES solar generation capacity may be partially phased in in preceeding years. A third block of 300MW may be added from 2012-2015.
/4 Figures shown represent the zonal reserve margin (IID's projected control area reserve margins are approximately 15-16% of IID's peak demand).

Source: IID Flexible Resources Plan for 2007 and Beyond (and other sources)

Table 3 reflects Imperial Irrigation District's (IID) plans to remove Unit no. 3 at its El Centro generating plant in 2010 as part of a repowering project. The unit would become part of a new combined-cycle configuration, resulting in the 117-MW increment shown in the Request For Proposals (RFP) No. 484 line of Table 3. Although Table 3 shows this increment in 2010, IID recently advised that the project will be postponed at least a year.[6]

Northern Baja California Zone Supply and Demand

In an effort to curb emissions, CFE plans to reduce the use of oil as a power plant fuel and become increasingly reliant on natural gas-fired generation in BC. Between 2009 and 2016, CFE plans to build an additional 1,568 MW of new generating capacity in Baja California as reflected in Table 4. Abundant fuel will be available to support this large-scale power plant expansion as a result of the construction of liquefied natural gas (LNG) terminal facilities, storage, and natural gas pipeline capacity in northern BC. Table 4 aggregates the Northwestern and Northeastern Baja California zones, which are then disaggregated in Tables 5 and 6.

---

[6] Personal communication with Noe Gutierrez, Imperial Irrigation District, on September 19, 2007.

Table 4: Electric Supply-Demand Balance (Baja California)

Plant Name	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	Net Generating Capacity [MW]										
In Operation	2352										
Retirements											
Cierro Prieto I					(75)						
New Entrants											
Baja California (Presidente Juarez)				252							
Baja California II (SLRC)				220							
Pte. Juarez GCT/CC Conversion					90						
Cierro Prieto V					100						
Baja California III (Ensenada)						279					
Baja California IV (Tijuana)								280			
Baja California V (SLRC) /1										271	
Baja California VI (Mexicali) /1											151
Total Capacity	2,352	2,352	2,352	2,824	2,939	3,218	3,218	3,498	3,498	3,769	3,920
Gross Peak Demand	2,007	2,097	2,223	2,334	2,479	2,624	2,769	2,921	3,086	3,251	3,425
Reserve Margin /2	17%	12%	6%	21%	19%	23%	16%	20%	13%	16%	14%

/1 Either new generating plant or PPA
/2 Minimum reserve margin for BC - after planned outages - the larger of: the largest gen unit or 15% of peak demand

Source: CFE, Programa de Obras e Inversiones del Sector Eléctrico 2007-2016

As shown in Table 4, electric resources in Baja California are keeping pace with demand, but as CFE's reserve margin declines in 2014-2016 CFE-owned resources may be supplemented with power purchases. However, the purchased power option is contingent upon the interconnection of the Baja California system to the rest of CFE via a high-voltage direct current (DC) line. This line is still under evaluation.

The following section describes the generation expansion and retirement plans for the northwestern (coastal) and northeastern (valley) areas of northern Baja California. To reduce seasonal transmission congestion between these two zones, CFE plans to locate new generation closer to the load centers. Table 4 shows this generation expansion plan through plants scheduled for construction near the growth areas of Tijuana-Rosarito, Mexicali, and San Luis Rio Colorado.

Northwestern Baja California Zone Demand and Resources

The current generation capacity in this area consists of several residual oil-fired units at the Presidente Juarez site near Tijuana: two 160-MW steam-cycle units, three combustion turbines with 210-MW capacity and two 248-MW natural gas-fired combined-cycle units. There is also a 55-MW oil-fired combustion turbine at the Ciprés site.

CFE generation plant additions and retirements in Northwestern Baja California, as shown in Table 5, include:

- The construction of a new 252-MW natural gas-fired combined-cycle facility at the Presidente Juarez site near Tijuana-Rosarito scheduled to go on-line on March 2009.
- The conversion of one of the existing units at Presidente Juarez to natural gas combined-cycle, yielding an additional 90 MW in capacity in April 2010.
- A not-yet-defined technology or fuel 279-MW facility in Ensenada in April 2011.
- An additional 280-MW plant, with undefined technology or fuel, is scheduled near Tijuana for April 2013. According to an earlier CFE report[7] this plant was to be located near Mexicali.

As Table 5 shows, the Northwestern zone has an abundance of capacity resulting in large reserve margins.

Table 5: Electric Supply-Demand Balance (Northwestern Baja California)

Plant Name	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	Net Generating Capacity [MW]										
In Operation											
Presidente Juarez - Steam	320										
Presidente Juarez - CC	496										
Presidente Juarez	210										
Cipres - GCT	55										
Retirements											
N.A.											
New Entrants											
Baja California (Presidente Juarez)				252							
Pte. Juarez GCT/CC Conversion					90						
Baja California III (Ensenada)						279					
Baja California IV (Tijuana)								280			
Total Capacity	1,081	1,081	1,081	1,333	1,423	1,702	1,702	1,982	1,982	1,982	1,982
Gross Peak Demand	849	887	941	988	1,049	1,110	1,172	1,236	1,306	1,376	1,449
Reserve Margin /3	27%	22%	15%	35%	36%	53%	45%	60%	52%	44%	37%

/1 Either new generating plant or PPA
/3 Western Baja California is not a control area, thus these figures only indicate the extent to which the area is capacity rich.

Source: CFE, *POISE 2007-2016*

Northeastern Baja California Zone Supply and Demand

The existing generation capacity in Northeastern BC is predominantly geothermal. CFE's 11 geothermal steam turbines have capacity of 720 MW. CFE also purchases the output of a 489-MW natural gas-fired combined-cycle plant at La Rosita generating complex under a long-term power purchase agreement (PPA). Lastly, a 62-MW oil-fired combustion turbine in Mexicali is used during the summer months.

[7] *Programa de Obras e Inversiones del Sector Eléctrico 2005-2014*, Comisión Federal de Electricidad.

The supply-demand balance presented in Table 6 shows that, under CFE's latest generation expansion plan[8], the northeastern area is short of capacity in 2008 and again from 2012 through 2016; this deficit will require power from the coastal area to flow over the 230-kilovolt (kV) east-west transmission lines to meet the inland valley load. As shown by the projected plant additions in Table 6, CFE plans to locate new generation closer to the load centers to help ease seasonal electricity transfers between coastal and valley areas.

Table 6: Electric Supply-Demand Balance (Northeastern Baja California)

Plant Name	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	Net Generating Capacity [MW]										
In Operation											
Mexicali (IPP-LRPC) CC	489										
Mexicali GCT	62										
Cerro Prieto I Geo.	180										
Cerro Prieto II Geo.	220										
Cerro Prieto III Geo.	220										
Cerro Prieto IV Geo.	100										
Retirements											
Cierro Prieto I					(75)						
New Entrants											
Baja California II (SLRC)				220							
Cierro Prieto V					100						
Baja California V (SLRC) /1										271	
Baja California VI (Mexicali) /1											151
Total Capacity	1,271	1,271	1,271	1,491	1,516	1,516	1,516	1,516	1,516	1,787	1,938
Gross Peak Demand	1,158	1,210	1,282	1,346	1,430	1,514	1,597	1,685	1,780	1,875	1,976
Reserve Margin /3	10%	5%	-1%	11%	6%	0%	-5%	-10%	-15%	-5%	-2%

/1 Either new generating plant or PPA
/3 Eastern Baja California is not a control area, thus these figures only indicate the extent to which the area is capacity rich.

Source: CFE, *POISE 2007-2016*

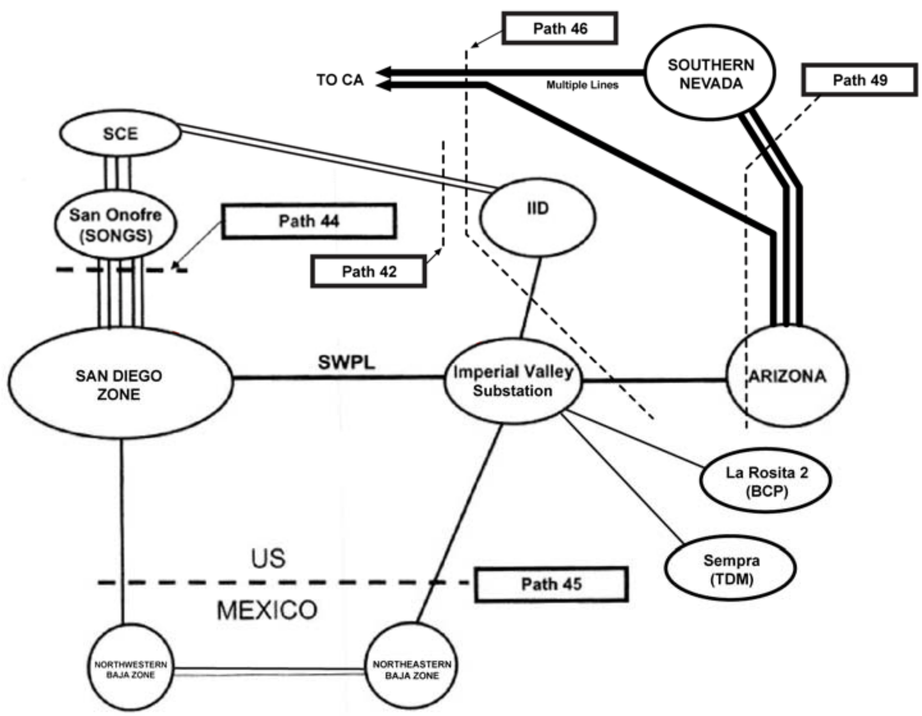
As shown in Table 6, CFE plans to commission a new natural gas-fired combustion turbine plant in 2009 at San Luis Rio Colorado (SLRC), which is located in the Northeastern Baja Zone near the border with Arizona. This generating complex will be located close to a large industrial park and will serve the industrial park demand and surrounding loads, thereby minimizing the need for additional 230-kV transmission capacity into the SLRC area.

[8] *Programa de Obras e Inversiones del Sector Eléctrico 2006-2017*, Comisión Federal de Electricidad.

CHAPTER 3: Current and Planned Bulk Electric Transmission Infrastructure in the California/Mexico Border Region

A simplified diagram of the major 230-kV and 500-kV electric transmission lines and interconnections in the United States/Baja California Norte, Mexico border region is shown in Figure 2. The 500-kV lines include the Southwest Powerlink (SWPL) from Arizona through the Imperial Valley to San Diego, and parts of Western Electricity Coordinating Council (WECC) Path 46 and Path 49, shown in bold in Figure 2. All the remaining transmission lines shown in Figure 2 are 230 kV.

Figure 2: Major Electric Transmission Facilities in the Border Region



Source: R.06-02-013, 2007-2016 Long-Term Resource Procurement Plan, SDG&E Exhibits, December 2006 (Edited)

The largest single block of generation in the region is the San Onofre Nuclear Generating Station (SONGS), with two nuclear units totally approximately 2,150 MW (net). The plant is physically located within the SDG&E service area, but the high-side 230-kV switchyard for the plant actually serves as the point of electrical interconnection between the SDG&E and SCE systems. This interconnection point is defined as WECC Path 44. As a result of this electrical configuration, the SONGS plant is electrically outside of the San Diego Zone.

As discussed in more detail later in the report, existing generation within the San Diego Zone totals slightly less than 3,000 MW. The majority of this capacity is located at the Encina Generating complex in Carlsbad, and the Southbay Generating Station in Chula Vista. Both plants are owned and operated by merchant generators. The largest SDG&E-owned plant in the zone is the Palomar Energy Project located in Escondido. Remaining generation in the San Diego Zone consists of relatively small peaker units.

The **Southeastern California Zone** includes both the Imperial Valley (IV) Substation oval and the *"IID"* oval shown in Figure 2. The IV oval represents IV500/230kV Substation as well as the generating plants that connect radially into the substation, including the Termoeléctrica de Mexicali (TDM) plant and La Rosita, both located in Mexico. These two merchant plants have a combined capacity of 1,210 MW. Existing generation within the IID oval includes 372 MW of IID-owned plants (Brawley, Coachella, El Centro, and Rockwood) and more than 550 MW of merchant-owned plants (primarily geothermal).

The **Northeastern Baja Zone** is represented by the La Rosita (ROA) oval in Figure 1. Existing generation in the zone connected to the CFE system totals about 1,270 MW. CFE has 11 geothermal steam turbines with 720 MW capacity at Cerro Prieto in addition to buying the output of 489-MW natural gas-fired combined-cycle capacity at the ROA generating complex under a long-term PPA. Another 560 MW of ROA are dedicated to the Southern California market. [10] CFE also owns a 62-MW oil-fired combustion turbine in Mexicali used as a peaker during the summer months.

The **Northwestern Baja Zone**, represented by the Tijuana (TJ) oval in Figure 1, has existing generation of 1,081 MW. This includes the following CFE owned generation at the Presidente Juarez site in Rosarito Beach: two 160-MW steam-cycle residual oil-fired units, three residual oil-fired combustion turbines with 210-MW capacity, and two 248-MW natural gas-fired combined-cycle units. There is also a 55-MW oil-fired combustion turbine used for peaking at the Ciprés site near Tijuana.

Electric Interfaces in the Border Area

The important electrical interfaces in the border area are indicated by dashed lines (cut planes) in Figure 2 and include the interface between IID and SCE (WECC Path 42), the interface between SCE and SDG&E (WECC Path 44), and the interface between northern Baja California (BCN) and California (WECC Path 45).

WECC Path 42 is rated 600 MW in the westbound direction (it is not rated eastbound) and is almost fully utilized for firm, long-term deliveries to SCE of the output from geothermal

[10] One generating unit at La Rosita can be disconnected from the plant and delivered through the Baja California Power plant switchyard (La Rosita 2), which is connected into the IV Substation.

generation physically located within IID's system. Without further upgrades, it is unlikely that Path 42 can support any significant amount of additional firm power delivery out of the Southeastern California Zone.

WECC Path 44 represents the southbound delivery capability from SCE/SONGS into the San Diego Zone. The path has as a normal rating of 2,200 MW and an emergency rating of 2,500 MW when any segment of the SWPL is out of service. It is currently the only path for firm power deliveries into the San Diego Zone during an outage of the IV-Miguel (ML) 500-kV line section.

WECC Path 45 represents the interface between California and Mexico's BCN system. It is a bifurcated path with one 230-kV line connecting the IV Substation 230-kV bus to the Northeastern BC Zone, and a second 230-kV line connecting the Miguel 230-kV bus to the Western BCN Zone. The "non-simultaneous" path ratings are 800 MW in the northbound direction and 408 MW in the southbound direction. The non-simultaneous designation means that the full path rating is only useable under certain system operating conditions such as during favorable simultaneous path flows and generation dispatch conditions. Therefore, schedules requested on Path 45 compete with other schedules on other paths for use of the available transmission infrastructure in the region such as northbound schedules on Path 45 often compete with generation schedules coming into the system at the IV 230-kV bus or import schedules from Arizona to California). Simultaneous flow conditions can cause congestion and/or operation of special protective systems (remedial action schemes) in either SDG&E or CFE systems. As a result, SDG&E assumes no firm deliveries across Path 45 in assessing its reliability needs.[11]

Because of the physics of power flow across the interconnected grid, two other major WECC paths shown in Figure 2 also affect power flows in the California-Baja border region. WECC Path 49 (east of the Colorado River), which defines the transmission interface from Arizona westward to Southern California and southern Nevada, includes the Hassayampa-North Gila 500-kV section of the SWPL along with numerous other EHV facilities further to the north. Secondly, WECC Path 46 (West of River) defines the interface westward from Arizona, southern Nevada and IID.[12] Although Path 49 is rated for more than 8,000 MW and Path 46 is more than 10,000 MW, this bulk power transmission capacity does not provide a path for interchange between the four zones in the California/Mexico border region. In fact, power flows and outage events on Path 46 and 49 can cause significant "through-flows" across the electric transmission infrastructure the California/Baja California, Mexico border region, thus reducing the amount of power transfer capability available for use on the local systems.

---

[11] San Diego Gas & Electric Direct Testimony in A.05-12-014, Application for Certificate of Public Convenience and Necessity for the Sunrise Powerlink, August 4, 2006 (Vol. 2, p. I-5)

[12] Southern California Edison's proposed Hassayampa-Devers 500kV (also known as the Devers-Palo Verde No. 2 "DPV2") line, if constructed, would also become part of both Western Electricity Coordinating Council Paths 46 and 49 increasing the respective path transfer capabilities.

It should be noted that the interface between IV Substation and the San Diego Zone (the IV–Miguel 500-kV line) is not part of any WECC rated path.[13] Power delivery over the IV-Miguel line is limited by the rating of substation facilities at both ends, as well as congestion on the SDG&E transmission system north of ML Substation. The transfer limit over the path is currently 1,750 MW.[14]

Lastly, the interface between Eastern BCN and Western BCN zones is made up of an older double-circuit 230-kV transmission line between La Rosita in the east and the Tijuana area in the west. The path is about 100 miles long and has a firm rating of roughly 250 MW, which is quite low and creates a significant operating limitation. There are no plans to increase the overall rating of the path or install a new circuit (or circuits) in parallel. When necessary, CFE shifts the generation dispatch between these two zones to stay within this transmission path constraint.

Transmission in Baja California

The evolution of the Baja California transmission system, illustrated in Figure 3, has been determined by the differences in the seasonal peak demands of the Coastal and Valley areas. This also resulted in most generating capacity being clustered around Tijuana-Rosarito (Coastal Zone) and Mexicali (Valley).

As shown in Figure 3, there are essentially two clusters of electric transmission in Baja Norte—one in the east and one in the west. Each of these clusters has a separate 230-kV tie with the U.S. grid—at Imperial Valley Substation in the east and Miguel Substation in the west. The two clusters are also connected together by a single transmission corridor that runs from La Rosita Substation in the east to Metropoli Substation in the west. In its current configuration, this Valley to Coastal area transmission path is a double-circuit, 230-kV with intermediate load-serving substations. The path has a "nameplate" capacity limit of 520 MW, but the practical operating limit is somewhat lower when exposure to transmission contingencies is taken into account. Load taken off at the intermediate substations along the line also reduces the net delivery capacity that can be delivered over the full length of the line. During the winter months, east to west peak flows of 250 to 280 MW are a result of the excess geothermal generating capacity flowing to the Coastal areas to meet its winter peak. During the summer, the flow reverses to 150 to 200 MW from the Coast to the Valley to meet summer air conditioning peak loads.

---

[13] IV-Miguel 500kV is the westernmost segment of the Southwest Powerlink (SWPL), which originates at the Hassayampa 500kV switchyard in central Arizona.
Segments of the line between Hassayampa and Imperial Valley Substation area jointly owned by San Diego Gas & Electric, Imperial Irrigation District and Arizona Public Service. The segment from IV to ML is wholly owned by San Diego Gas & Electric.
[14] San Diego Gas & Electric Rebuttal Testimony, A.06-08-010, Linda Brown (48:1-14), June 15, 2007.

Planned Electric Transmission Upgrades

Southeastern California:

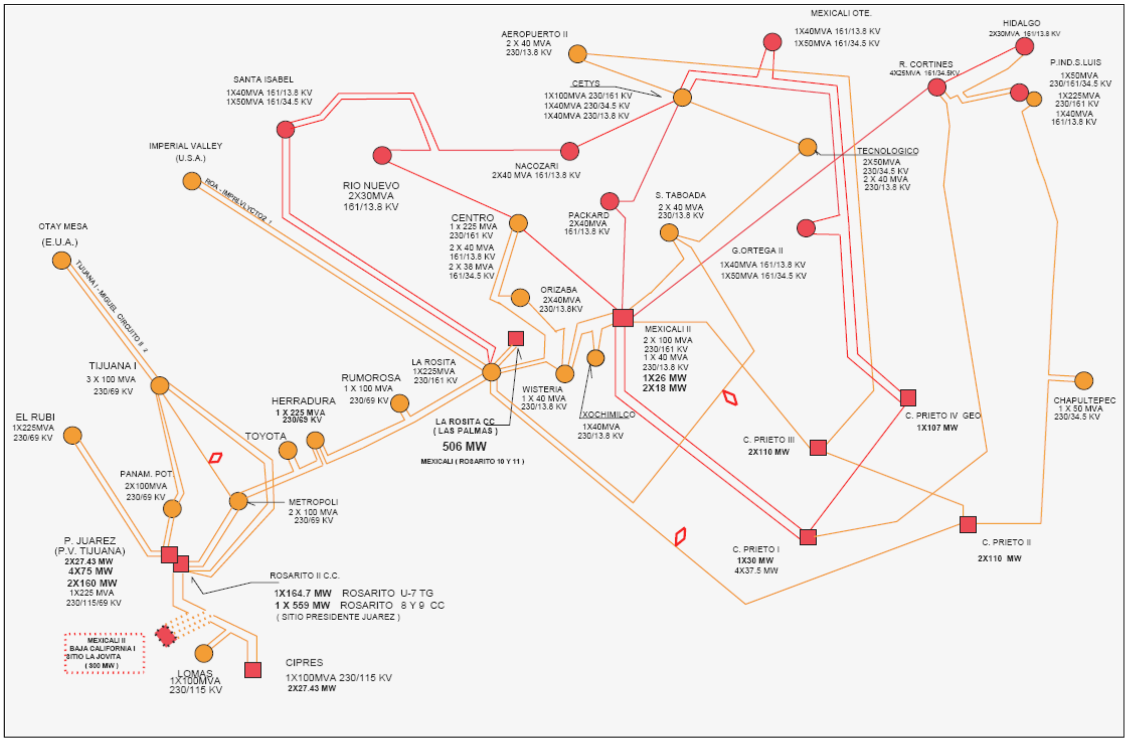
Sunrise Powerlink

- SDG&E proposes construction of a second major transmission line from IV Substation into San Diego, called the Sunrise Powerlink.[15] This project is shown as a dashed red line in Figure 2 and would increase the import capability of the San Diego Zone approximately 1,000 MW. As shown in more detail in Figure 4, this proposed scope includes a new 500-kV line from IV Substation to a new substation in east central San Diego County (the solid black line represents two segments of the existing SWPL). From the new Central Substation, 230-kV facilities would extend further west and connect into other existing substations. SDG&E estimates the project cost about $1.3 billion (including allowance for funds used during construction)[16]. Their proposed in-service date for the project is summer 2010.

---

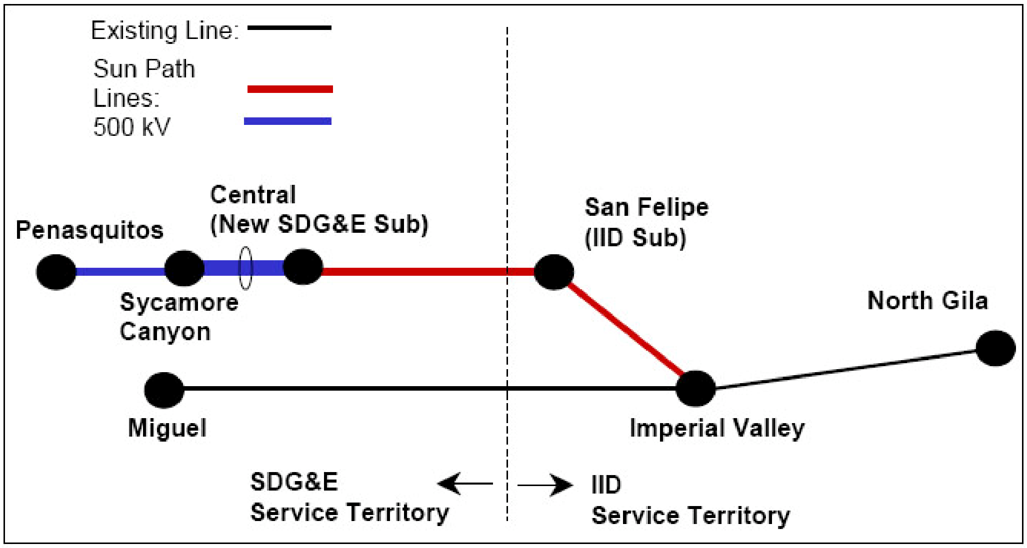
[15] California Public Utilities Commission Proceeding A.06-08-010 (formerly A.05-12-014) for Certificate of Public Convenience and Necessity ("CPCN") for the Sunrise Powerlink Transmission Line.
[16] San Diego Gas & Electric Direct Testimony, A.05.12.014 (Vol. 2, pp I-4).

Figure 3: Baja California Transmission System



Source: CFE Planning Subdirectorate

Figure 4: Simplified Diagram of Sunrise Powerlink



Source: California ISO

The purported benefits of the project include:

- Increased access to renewable resources from the Imperial Valley and northern Mexico.
- Improved reliability for the SDG&E service area due to an increase in their system import capability.
- Economic benefits to ratepayers including savings from declining reliability must run contracts.

SDG&E posits that the Sunrise project would allow developers of renewables throughout the border region to consummate power sales contracts with SDG&E and other parties by augmenting bulk power transmission capacity in the region. In SDG&E's view:

> This will greatly facilitate financing for the (renewable) projects since it will both reduce a substantial development risk involving access to the grid and will increase the range and volume of financially viable projects that could be developed. [17]

Although intervenors in the regulatory proceeding for the Sunrise project have challenged the extent to which Sunrise would produce these benefits, there is general agreement that such benefits will accrue from the proposed project. Intervenors have also suggested various alternatives including route options, a reduction in the 230-kV portion of the project, construction of new generation in the San Diego Zone and other concepts that might defer the need for Sunrise. Filed testimony in the proceeding was completed in June 2007. Evidentiary hearings on the project were scheduled in two phases. Phase 1, addressing the need, scope, and benefits, was held from July-September 2007. Phase 2, addressing routing and environmental issues, was conducted in April-May 2008. The outcome of this proceeding is yet to be determined and the California Public Utilities Commission (CPUC) is expected to issue a decision in late 2008.

Independent of the CPUC proceeding, the Energy Commission had previously concluded that the Sunrise Powerlink would increase access to renewable power in the Imperial Valley as well as greater access to lower cost out-of-state generation (including Baja California).[18] The California ISO agrees that the line would increase access to renewable power, particularly from the Imperial Valley.[19] SDG&E has already executed at least one power purchase agreement for 300 MW of solar generation from the Imperial Valley beginning in June 2010 with Sterling Energy Systems (SES), increasing to 600 MW by 2012. This initial 600-MW purchase has been approved by the CPUC. The contract is expandable to 900 MW from 2012-2016, if SDG&E elects to do so, subject to CPUC approval.[20] SDG&E says delivery of SES plant output hinges upon successful expansion of the electric transmission infrastructure from the Imperial Valley to the

[17] San Diego Gas & Electric Rebuttal Testimony, A.06-08-010, Linda Brown (50:1-12).
[18] "Strategic Investment Plan", California Energy Commission proceeding 04-IEP-1K, November 21, 2005.
[19] California Independent System Operator Initial Testimony, A.06-08-010, Part 1, January 26, 2007 (pp. 6).
[20] San Diego Gas & Electric Direct Testimony, A.05-12-014 (Vol. 2, pp III-11).

west but admits that the initial phase may be deliverable without the Sunrise Powerlink.[21] Although far short of the estimates of resource potential for the valley, the California ISO concludes that up to 500–700 MW of new renewable power could be added in the Imperial Valley in the absence of the Sunrise Powerlink.[22]

In its Sunrise Powerlink filings, SDG&E also acknowledged looking into a lengthier "full loop" concept that would go beyond the current Sunrise project scope by completing a full 500-kV loop through the SDG&E service area and connecting into SCE in the greater Los Angeles area. Without such an additional 500-kV section between Sunrise and SCE, flows over Sunrise would have to flow through SDG&E's lower voltage transmission facilities to reach the SCE system, thus limiting the value of Sunrise to the overall California ISO controlled grid. SDG&E has testified that based on joint studies of transmission expansion alternatives done in conjunction with the California ISO and numerous stakeholders:

> The full loop alternative provided the highest economic benefit and had the largest California ISO ratepayer benefit. Also, like the Sunrise Powerlink (which essentially comprises a portion of the full loop option), the full loop alternative would provide some of the best access to renewable resources. [23]

SDG&E testified that it may propose completing the full loop concept in the future, but doesn't think it is needed for reliability purposes until at least 2020.[24] However, at this time, SDG&E has filed solely for an Imperial Valley to Central Substation 500-kV line in its proposed plan of service for Sunrise (along with lower voltage upgrades internal to its service area). SDG&E's decision in this regard may be short-sighted since it ignores potentially greater benefits of the Full Loop approach that could accrue between 2010-2020.

SDG&E 500/230kV Substation for Wind Generation

In the Sunrise hearings SDG&E also disclosed plans to build a new 500/230-kV substation in southeastern San Diego County for the purpose of interconnecting wind renewable resources. This substation, which is independent of the Sunrise Powerlink proposal, will tie into SDG&E's existing Imperial Valley–Miguel 500-kV line.[25] The exact location, timing, and licensing status of the substation were unclear from SDG&E's testimony, but if a Certificate of Public Convenience and Necessity (CPCN) application is filed in a timely manner it should be possible to license the

---

[21] California Public Utilities Commission Hearing Transcript for A.06-08-010, Testimony of Michael McClenahan, San Diego Gas & Electric (1115:25-1116:15).
[22] California Independent System Operator Rebuttal Testimony, A.06-08-010, filed August 4, 2007 (25:8-26:12).
[23] San Diego Gas & Electric Amended Direct Testimony, A.06-08-010, Dec. 14, 2005 (Vol. 2, Jan Strack/Victor Kruger, VI-ii).
[24] California Public Utilities Commission Hearing Transcript for A.06-08-010, Testimony of Linda Brown, San Diego Gas & Electric (547:1-549:1).
[25] Ibid., Testimony of Ali Yari, San Diego Gas & Electric (893:4-896:11).

substation and have it built in the 2010 timeframe. It is important to note that the proximity of this substation to the La Rumorosa area of Baja California would make it an excellent point of interconnection for Mexican wind renewables in that region, as well as any future gas-fired generation projects that may develop in the area.

Green Path Project

A second major 500-kV transmission proposal in Southeastern California is Green Path North, sponsored by the Los Angeles Department of Water and Power (LADWP). This project is shown as the dashed line in Figure 5 that runs between Hesperia Substation (near the top of the figure) to a new substation (Devers 2) to be built near SCE's existing Devers Substation.

The projected in-service date for Green Path North is 2010-2011. The dashed line between Hassayampa-Devers-Valley in Figure 5 is a separate 500-kV project proposed by SCE (Devers-Palo Verde No. 2 project)[26]. The dashed lines from Devers 2 to Coachella Valley and further to the south are additional lower voltage upgrades sponsored by IID. According to IID, the earliest possible in-service date for its Indian Hills-Coachella-Devers 2 (500-kV) line is 2011. Due to IID's concern about the potential of stranded assets, other IID area upgrades shown in the figure will be staged to coincide with development of new renewable resources in the Imperial Valley.[27]

LADWP has filed path rating studies with the WECC that support a non-simultaneous northbound rating of 1,200 MW for the Green Path North line. Their analysis also found that an additional 400 MW of path rating would be available if the existing Lugo – Rancho Vista 500-kV line is looped into Hesperia Sub, and a second 500-kV link is built from Lugo to Hesperia.[28] The specific design(s) and rating(s) of the IID upgrades to the south of Devers 2 are yet to be determined, and the transfer limit between Devers 2 and the existing Devers Substation is also undetermined at this time.

Closing a 230-kV path from IV Substation northward through the IID system to Devers, as indicated in Figure 5, could increase the simultaneous delivery capability out of Baja California and the IV area. However, simultaneous rating sensitivities have not yet been conducted to quantify this potential benefit.

A previous stakeholder study has concluded that the Sunrise Powerlink, in conjunction with internal IID area upgrades, would permit export of up to 2,200 MW of renewable resources from the Imperial Valley.[29] This represents an increase of 1,375 MW over the current (825 MW) export capability from IID to the California ISO controlled grid. The California ISO concludes

---

[26] The eastern terminus of the proposed Devers-Palo Verde No. 2 (DPV2) line is actually the Hassayampa Substation, which is adjacent to Palo Verde Substation. Hassayampa and Palo Verde are connected by 500-kV bus ties and are treated as a "common bus" for delivery purposes.

[27] Personal communication with Juan Sandoval, Imperial Irrigation District, July 2007.

[28] *Western Electricity Coordinating Council Path Rating Study for Green Path North*, June 2007.

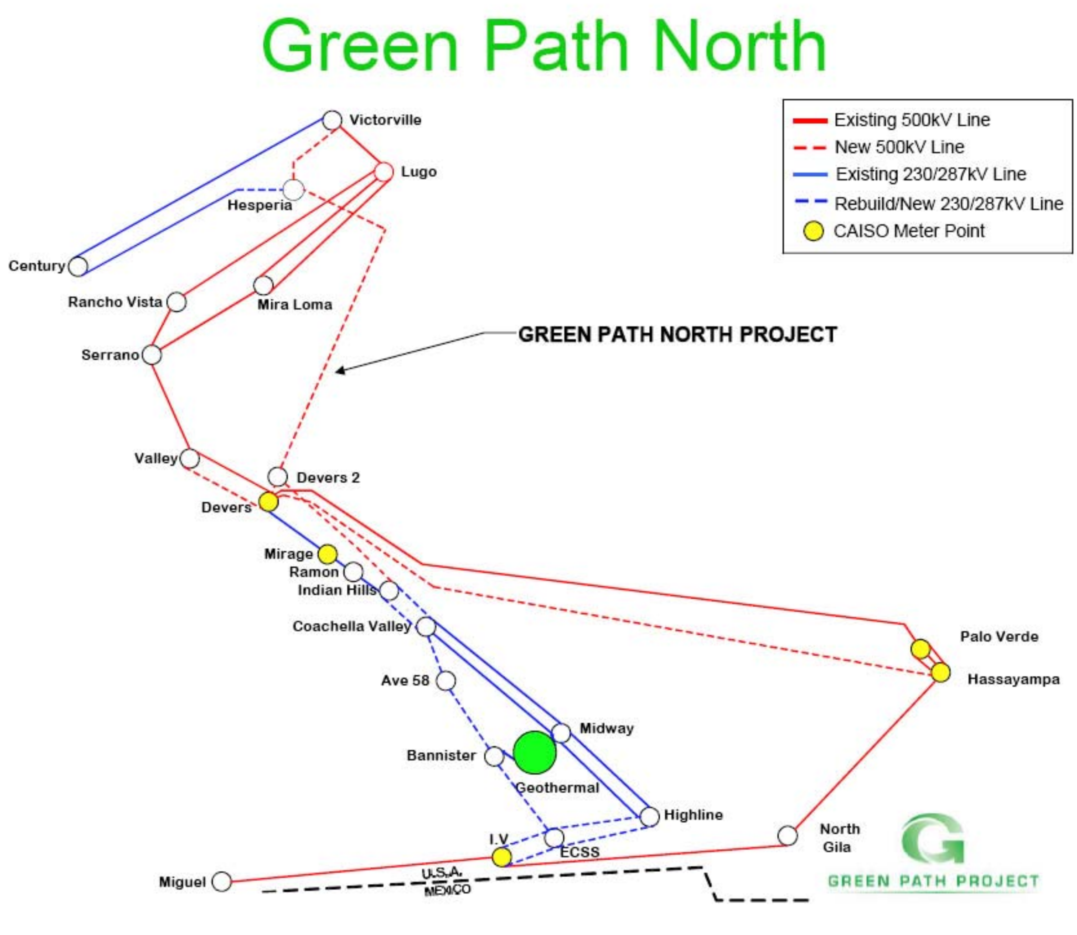
[29] Report of the Imperial Valley Study Group, September 30, 2005.

that export of IV renewable power over the Green Path North project (absent Sunrise) would be only 500 MW.[30]

Neither the Sunrise Powerlink nor the Green Path project would increase the export limit from Baja California, Mexico to California, which is limited by WECC Path 45. Since none of the proposed facilities associated with Sunrise or Green Path cross the United States/Mexico border, the configuration of Path 45 would remain unchanged. However, the SDG&E and LADWP projects could indirectly affect Path 45 as follows:

- The Sunrise Powerlink should reduce congestion on SDG&E's transmission facilities west of IV, thus allowing more energy to be scheduled northbound on Path 45.
- Increased scheduling capability and infrastructure on the north side of the border may provide additional incentive to upgrade the capacity of Path 45.

Figure 5: Green Path Project (North and South)



Source: Los Angeles Department of Water and Power

[30] California Independent System Operator Rebuttal Testimony, A.06-08-010 (39:11-40:3).

Northern Baja California Transmission System Expansion

As the electric demand of both its Valley and Coastal areas continues to grow, CFE has planned for new generating capacity close to each load center in an effort to reduce the need for additional east-west transmission capacity.

Except for plans to add transformer capacity at several substations, CFE is planning two transmission system additions CFE for Baja California between 2007 and 2016. One is a second 230-kV circuit between the Metropoli Potencia and Tijuana I substations, linked to the new 252-MW Baja California combined-cycle generating facility at Rosarito's Presidente Juarez (site slated to begin service in 2009). The other project includes a number of 230-kV line additions in the Valley system: a double-circuit line connecting Parque Industrial San Luis-Cerro Prieto I-Hidalgo (mid-2007), a four-circuit line connecting Ejido San Luis-Cerro Prieto II-Parque Industrial San Luis, and a double-circuit line between Cerro Prieto II and Parque Industrial San Luis (October 2008). This could facilitate exports of geothermal power to California, if CFE elects to market any of this energy.

Planned Electric Generation Additions and Retirements

Following are descriptions of the new generation plants that are being proposed in the border region. This discussion also includes the effect of these plants on the transmission capacity of the border area.

Otay Mesa Generating Plant

A major combined-cycle generating plant is currently being built at Otay Mesa along the southern border of the San Diego Zone, about one mile north of the United States/Mexico border. The Energy Commission granted siting approval for this generation project in April 2001. The plant is being built by Calpine and, per its contract requirements with SDG&E, has commercial operation date before the summer of 2009.[31]

When the Energy Commission licensed the plant, the only transmission to be built was a loop-in of the existing Tijuana-Miguel 230-kV line into the plant switchyard along with converting the existing 230-kV line section between the Otay plant site and Miguel Substation from a single-circuit line into a double-circuit line. In 2003, SDG&E determined that additional 230-kV transmission would be needed to allow firm dispatch of Otay Mesa and to ensure delivery of the output to load centers in the San Diego Zone. On this basis SDG&E proposed, and the

[31] California Public Utilities Commission Hearing Transcript for A.06-08-010, Testimony of Frank Thomas, San Diego Gas & Electric (1230:22-24).

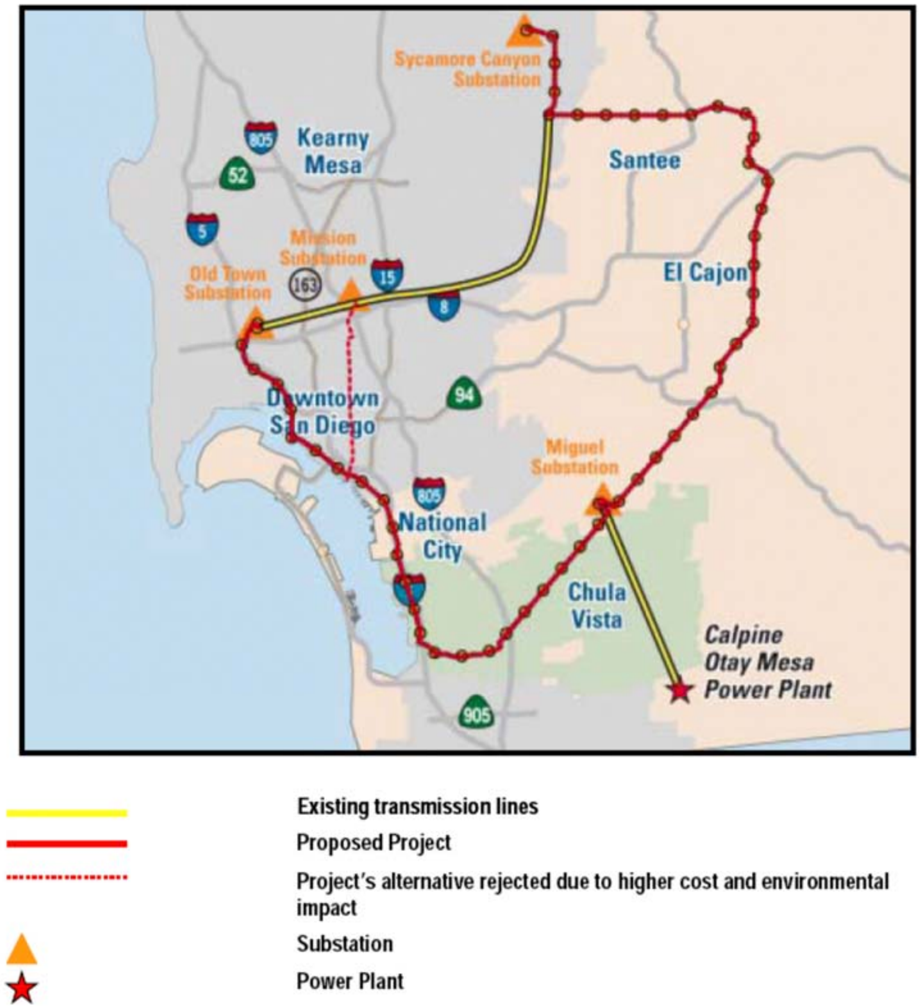
CPUC approved a 230-kV transmission expansion.[32] Figure 6 shows a diagram of this revised transmission plan.

The expanded Otay Mesa transmission plan includes a new 230-kV circuit from the Miguel area to Sycamore Canyon Substation in the east and a second 230-kV circuit from Miguel to Old Town Substation near the coast. Both circuits pass by Miguel Substation, but under normal operation when the Otay Mesa Generating Plant is in service both lines will bypass Miguel electrically to avoid congestion and operating problems in the area. SDG&E recently completed construction of these two transmission circuits: the double-circuit segment from the Miguel area to the new Otay Mesa plant switchyard remains to be built.

Even though the Otay Mesa plant site is close to the border with Baja California, the transmission plan for the project does not expand the transmission capability from Baja California into the San Diego Zone. There are currently no plans to upgrade the single existing 230-kV circuit between the Otay Mesa site and Tijuana (not shown in Figure 6). Therefore, the Otay Mesa transmission plan will not increase of the rating of WECC Path 45.

[32] Decision in A.04-03-008, June 30, 2005.

Figure 6: Electric Transmission Expansion for Otay Mesa

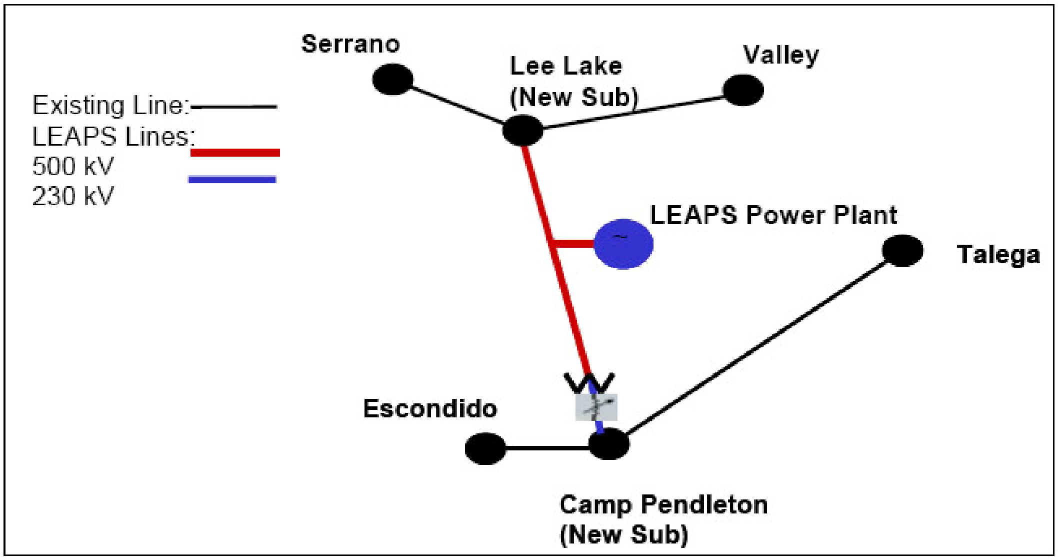


Source: CPUC

LEAPS Pumped-Storage Project

Nevada Hydro has proposed a major generating plant to interconnect into the north side of the San Diego Zone. The project includes a 500-MW pumped-storage generating facility located at Lake Elsinore, just north of the SDG&E service area in the Cleveland National Forest. The proposal is known as the Lake Elsinore Advanced Pumped Storage (LEAPS) project and includes a new 500-kV transmission corridor along a north-south alignment that would connect the generating plant to both SCE and SDG&E as shown in Figure 7.

Figure 7: Simplified Interconnection Diagram for LEAPS



Source: California ISO

Nevada Hydro has filed with the United States Federal Energy Regulatory Commission (FERC) for a license to build the project.[33] They have also petitioned the FERC for approval to build the transmission tie between SCE and SDG&E, referred to as the Talega-Escondido/Valley-Serrano 500-kV interconnect project (TE/VS Interconnect) in advance of the generating plant. Interconnection studies have been completed for the project by SCE and SDG&E, in conjunction with the California ISO, but they are confidential and therefore not available for review or discussion. A limited amount of transmission system technical analysis has been performed and published by the California ISO for the LEAPS project. An interim California ISO assessment of done for LEAPS assumed both the Sunrise Powerlink and Green Path lines (Sun Path Project) were in service.[34] The California ISO concluded that a TE/VS line could deliver about 1,000 MW into SDG&E, as long as the Sun Path facilities were in service.[35] Without the Sun Path upgrades, the California ISO estimates the delivery capability into SDG&E on a TE/VS line would be 500 MW.[36]

---

[33] "United States Federal Energy Regulatory Commission Project 11858: Lake Elsinore Advanced Pump Storage Project"/*Federal Register*/Vol. 71, No. 196, October 11, 2006.

[34] California Independent System Operator refers collectively to the Sunrise Powerlink and Green Path lines as the "Sun Path." The California Independent System Operator Board has granted its approval for both lines.

[35] *California Independent System Operator South Regional Transmission Plan for 2006 (CSRTP-2006)*, Presentation to California Independent System Operator Board, September 6-7, 2006.

[36] California Independent System Operator Rebuttal Testimony, A.06-08-010 (21:21:10-12).

CHAPTER 4:
Current and Planned Natural Gas Pipelines and Infrastructure in the California/Mexico Border Region

Natural Gas Transmission Pipelines

California receives natural gas supplies from diverse sources including Canada, the Southwestern United States (Permian, Anadarko, and San Juan Basins), the Rocky Mountains, and sources within California. Interstate pipelines currently serving California include El Paso Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission-Northwest, Transwestern Pipeline Company, Questar Southern Trails Pipeline, and Tuscarora Pipeline. Supplies are transported to the California border and are redelivered primarily via intrastate transmission lines to ultimate natural gas consumers. The historical peak send-out to customers in California is approximately 5.2 billion cubic feet per day (Bcfd).

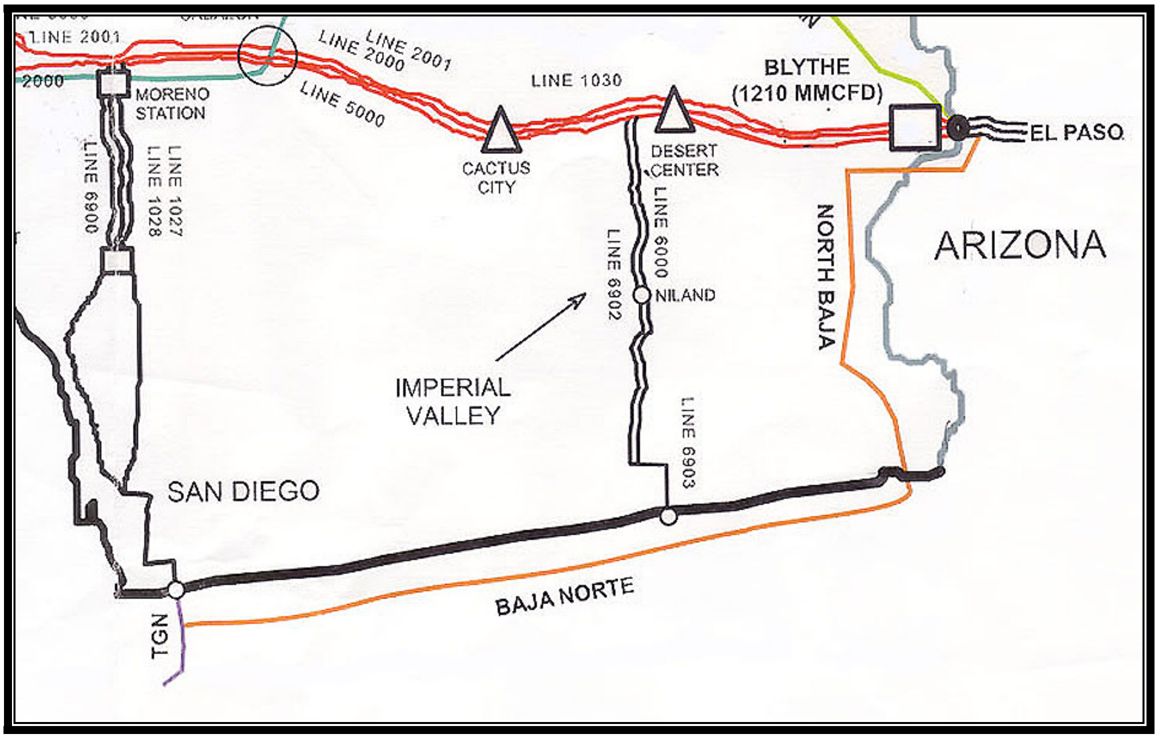
Figure 8 is a map of the of the natural gas transmission facilities, both interstate and intrastate, serving the California/Baja California Norte border region extending approximately 60 miles to the north and south of the California/Mexico border. The main east-west gas pipeline corridor on the California side of the border, from Blythe to Moreno Station, is actually just north of the Southeastern California and San Diego zones. The North Baja Pipeline, which originates in western Arizona, passes through southeastern California en route to Mexico. However, it currently does not serve any customers in California.

As shown in Figure 8, the firm interstate pipeline delivery capability into Southern California at Blythe is more than 1,210 MMcfd (an additional 250 MMcfd available on a non-firm basis). SoCalGas has a total system-wide firm supply capacity from interstate and local sources of 3,875 MMcfd. [37] In addition, it has approximately 130 billion cubic feet (Bcf) of on-system storage capacity with the ability to withdraw from storage up to 3.5 Bcf per day (Bcfd).[38] However, none of these storage facilities are located in the border region.

---

[37] *California Gas Report 2006*.
[38] Interview with SoCalGas, May 29, 2007.

Figure 8: Border Region Natural Gas Facilities



Source: SoCalGas

As shown in Figure 8, the SoCalGas transmission system in the border region has drop-off points to the Imperial Valley and Moreno/San Diego. A portion of the interstate gas supply coming in at Blythe drops off at these points, and the rest continues on to the major load center(s) further to the west of Moreno.

Southeastern California Zone

The Southeastern California border zone is principally served by SoCalGas through its local transmission Line 6902 (Figure 8). The gas enters the SoCalGas backbone transmission system from El Paso at Blythe, travels west to Line 6902 and south through the Imperial Valley to the California/Mexico border. Natural gas is also delivered through that line to ECOGAS (formerly Distribuidora de Gas Natural de Mexicali), which distributes natural gas to retail customers in Mexicali, Mexico.

Southeastern California is a summer peaking system. The major customer on that system is the Imperial Irrigation District (IID), which uses natural gas to fuel its power plants. The capacity of the system is currently 86 MMcfd.[39] In addition to serving the Imperial Valley, SoCalGas provides up to 25,200 MMcf/d of firm capacity to ECOGAS.

San Diego Zone

SoCalGas also delivers gas to three wholesale utility customers in the Southern California region including San Diego Gas & Electric Company (SDG&E), Southwest Gas Corporation and the City of Long Beach Energy Department. The San Diego Zone currently receives 100 percent of its gas supply from SoCalGas. The vast majority of its gas is delivered through the Moreno compressor station in Moreno Valley (see Figure 8), travels south along three high-pressure transmission lines to the Rainbow Station, where pressure is boosted again into the 16-inch transmission line (there is also a 30-inch high-pressure line from Rainbow Station to the SDG&E system) for ultimate delivery to SDG&E city-gate stations.

Given the current geographic configuration of natural gas customers, the SDG&E system has the capacity to serve 640 MMcfd of demand in the winter and 625 MMcfd of load in the summer.[40] These figures do not include 45 MMcfd reserved for operating margin. Because of recent growth along the Rainbow Corridor, the capacity of the SDG&E transmission system has been reduced from the November 2006 estimate of 655 MMcfd in the winter and 635 MMcfd in the summer.[41]

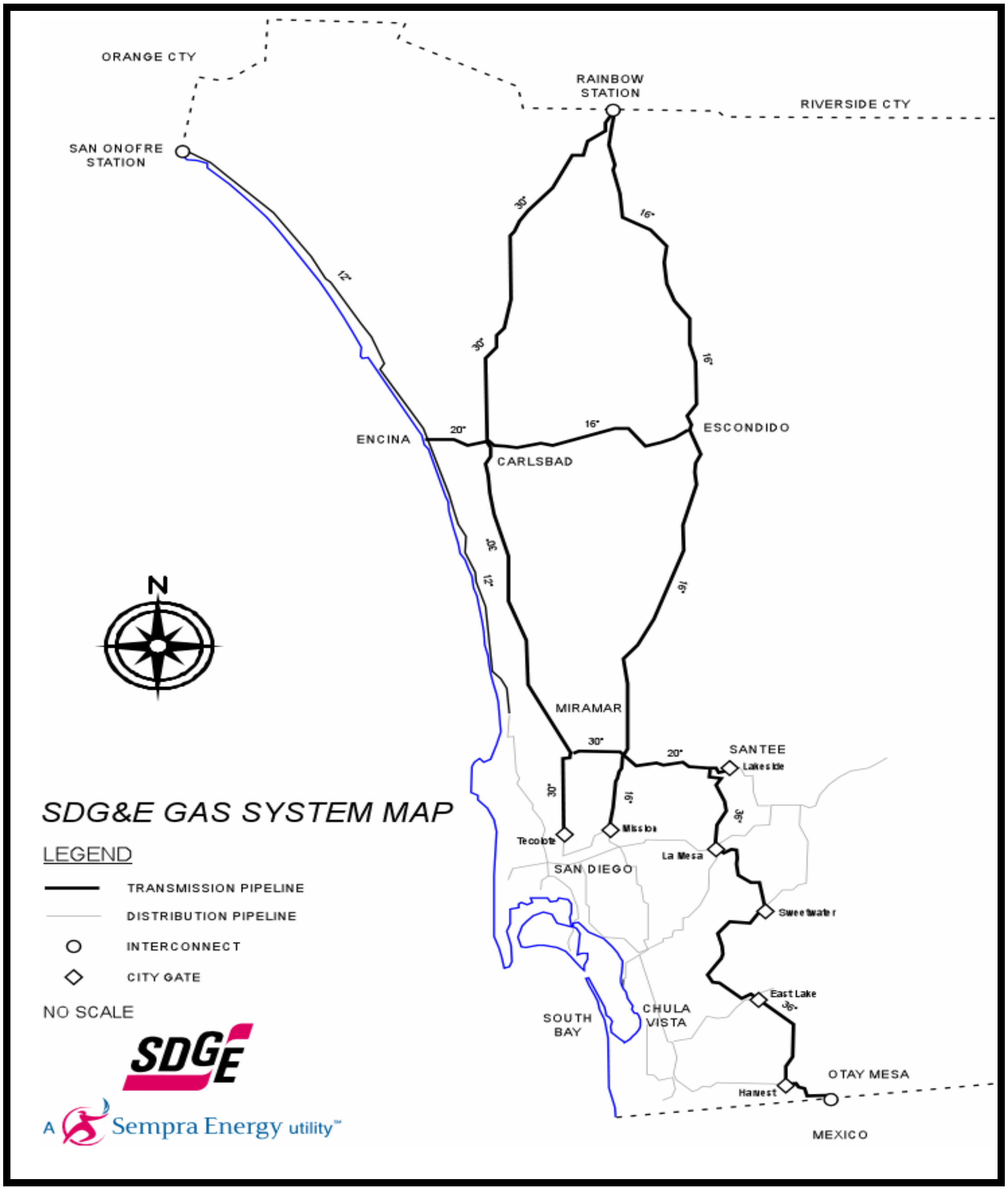
Baja California Zone(s)

Figure 10 shows the natural gas transmission facilities used to serve the northern Baja California zones. Although the North Baja Pipeline is located in Riverside and Imperial Counties of California, the pipeline currently only serves markets in Baja California. This region of Mexico is not physically connected to the Mexican natural gas pipeline system and must rely on gas imported through California to meet its growing natural gas needs. However, this dependency will change when the Costa Azul liquefied natural gas (LNG) receiving terminal is completed on the Baja California coast.

---

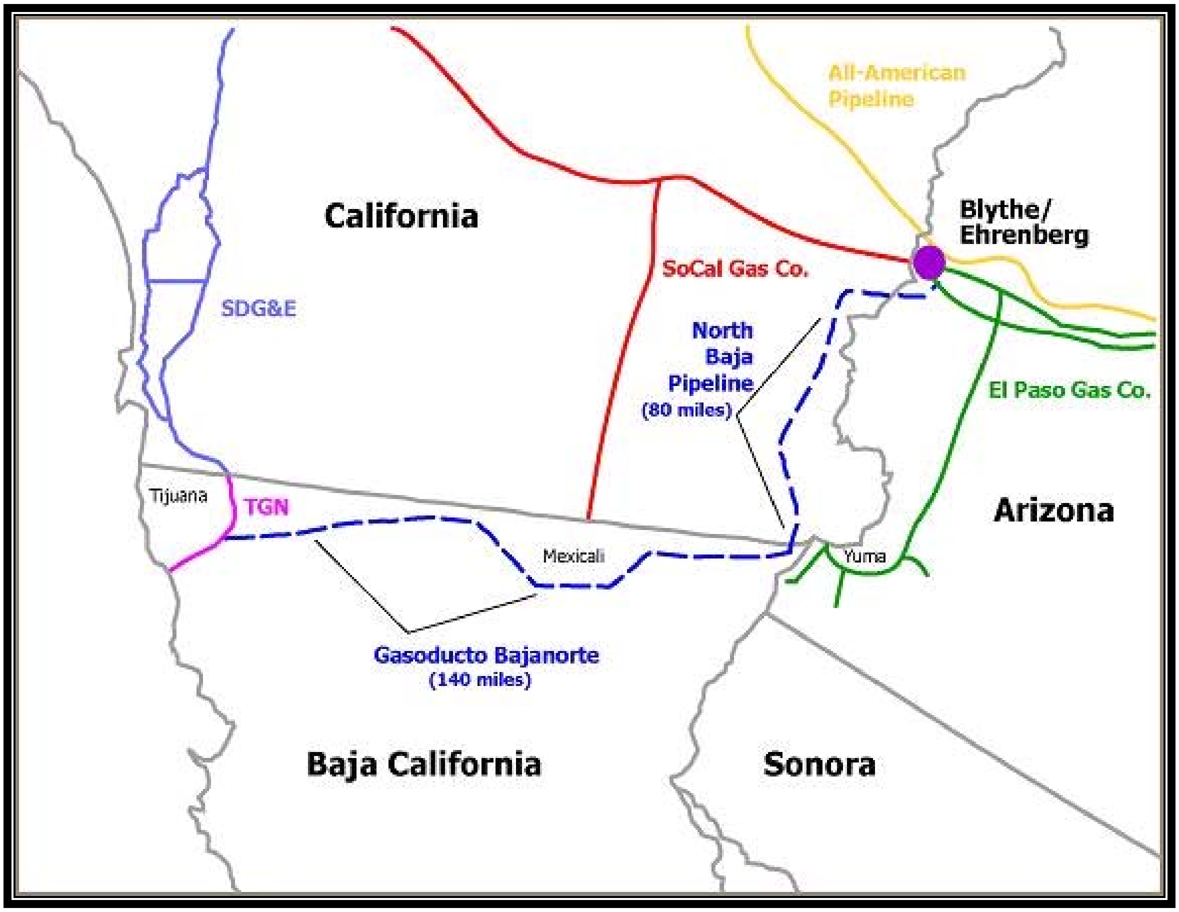
[39] Advice Letter AL3474 filed June 1, 2007, with California Public Utilities Commission.
[40] San Diego Gas & Electric, *Gas Capacity Planning and Demand Forecast Semi-Annual Report*, filed May 4, 2007 with California Public Utilities Commission.
[41] Testimony of David M. Bisi of San Diego Gas & Electric in A.06-10-XXX filed October 27, 2006, with California Public Utilities Commission.

Figure 9: SDG&E Natural Gas Transmission System



Source: SDG&E

Figure 10: Natural Gas Pipelines Serving Baja California



Source: Sempra

The North Baja Pipeline (NBP), Gasoducto Bajanorte (GB) and the Transportadora de Gas Natural de Baja California (TGN) systems comprise an approximately 245-mile transmission system that serves the growing natural gas demand in Baja California. The NBP system consists of a 30-inch and 36-inch pipeline approximately 80 miles long. The GB system consists of a 30-inch pipe approximately 140 miles in length. Natural gas enters the North Baja system from El Paso Gas Co. at Blythe/Ehrenberg and travels south to GB, where it moves west and connects to TGN. The North Baja and GB portions began service on September 1, 2002, with an initial capacity of 200 MMcfd. Completion of the pipeline's 21,000-horsepower compressor station in December 2002 brought the pipeline's capacity to 500 million cubic feet per day in December 2002. The North Baja Pipeline is owned by TransCanada and the GB system is owned by Sempra Energy.

TGN’s natural gas transmission line, also owned by Sempra Energy, is 23 miles long and 30 inches in diameter and has the capacity to transport up to 300 million cubic feet of gas per day (southbound).[42] TGN began to supply natural gas from the United States/Mexico border near San Diego to the Presidente Juarez power plant in Rosarito, Baja California, in the summer of 2000. Under a 10-year agreement, Sempra Energy companies provide a complete energy supply package to the plant, including potentially buying up to 300 million cubic feet per day of natural gas in the United States and transporting it across the border to the plant (although Rosarito cannot currently use that much gas.) TGN starts at the interconnection with the GB system in the Tijuana area and terminates at the Presidente Juarez Thermoelectric CFE Central in Rosarito, Baja California.

[42] The capacity should become bidirectional after Sempra completes planned upgrades.

CHAPTER 5: Natural Gas Supply-Demand Balance, Flows, and Flow Limits Between Zones

Although surplus electric and gas resources exist in some of the zones studied, export of surpluses to adjacent zones is limited by the transmission infrastructure. This section of the report describes the existing interfaces and flow limits between the zones, as well as proposed infrastructure projects that may affect the flow limits in the future.

San Diego Zone

Supply Capacity

The SDG&E gas distribution system receives virtually all of its gas supply from SoCalGas along the Rainbow Corridor. The Rainbow Corridor consists of three high-pressure transmission lines between the Moreno and Rainbow compressor stations. The capacity of the SDG&E transmission system is currently 640 MMcfd in the winter and 625 MMcfd in the summer, plus an operating reserve of 45 MMcfd. This capacity is based on the current geographic configuration of customers and demands they place on the system. The transmission capacity of this system will change as the distribution of its customers' demand changes. For example, if more customer demand were located in the southern portion of the SDG&E system, such as the San Diego metropolitan area, the capacity of the system would decrease even if overall customer demand didn't change. This variability in the capacity of the transmission system is caused by the need to maintain increasingly higher pressures to push more gas further south to serve customers in the southern-most end of the SDG&E system.

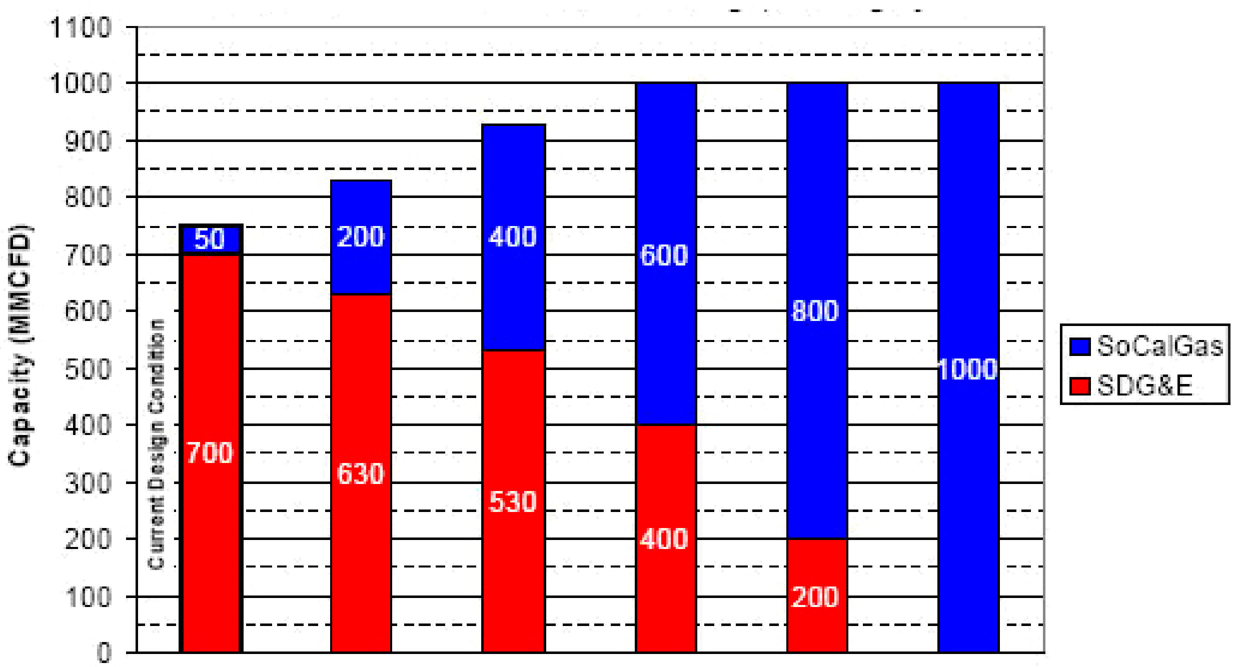
In addition, demand on SoCalGas' Rainbow Corridor also affects the capacity of the SDG&E system. SoCalGas' Rainbow Corridor pipelines have the capacity to serve one Bcfd of demand located within Riverside County between the Moreno and Rainbow Stations.[43] SDG&E's higher-than-minimum pressure requirements, however, has the effect of reducing the capacity of that system as well. Pipeline pressure drops as gas is taken out of the pipe. As the minimum operating pressure requirement increases in the Rainbow Corridor, the amount of gas that can be taken off the pipe decreases. This relationship results in a lower pipe capacity.

Figure 11 shows a range of scenarios illustrating the relationship between SoCalGas' capacity south of Moreno vs. demand on the SDG&E system, assuming the current SDG&E customer demand configuration. For each scenario shown in the graph the red bar represents SDG&E

[43] Testimony of David M. Bisi of San Diego Gas & Electric in A.06-10-034 filed October 27, 2006, with California Public Utilities Commission. Rainbow is located just south of the Riverside County-San Diego County boundary.

demand and the blue bar represents the corresponding limit on deliveries to SoCalGas' customers (existing and future) between Moreno and Rainbow. The sum of the red and blue bars in each scenario represents the aggregate delivery capability over the SoCalGas pipeline south of Moreno. As shown in Figure 11, when the demand on the SDG&E system exceeds 400 MMcfd, the capacity of the total system begins to decline, dropping from 1,000 MMcfd to 930 MMcfd as SDG&E demand increases from 400 MMcfd to 530 MMcfd. Conversely, if customer demand increases on the SoCalGas system north of Rainbow, pressures at Rainbow Station will decline along with delivery capability into the SDG&E system.

Figure 11: Moreno-Rainbow Corridor vs. San Diego, Existing System



Source: Testimony of David Bisi of SoCalGas filed on October 27, 2007 before the CPUC

SDG&E estimates that if core demand along the Rainbow Corridor continues to grow at its current pace, SDG&E system capacity could decline to 630 MMcfd in winter and 610 MMcfd in summer if no system enhancements or other actions are implemented.[44]

Demand

In D.02-11-073, the CPUC affirmed peak-day design criteria of a 1-in-35-year cold day condition for firm core service, and established a new 1-in-10-year cold day condition requirement for non-core firm service. That is, SDG&E must maintain its system to be able to provide

---

[44] San Diego Gas & Electric, *Gas Capacity Planning and Demand Forecast Semi-Annual Report*, filed May 4, 2007, with California Public Utilities Commission.

continuous service to core customers on the coldest day expected to be experienced in its service territory in a 35-year period. It must also be able to meet its firm non-core daily requirements on the coldest day expected to be experienced in a 10-year period.

In D.02-11-073, the CPUC authorized SDG&E to conduct an open season for the allocation of capacity on its gas transmission system. In D.06-09-039, the CPUC authorized both SDG&E and SoCalGas to conduct open seasons for the allocation of capacity on any portion of its gas transmission system which is, or is expected to be, constrained. As of May 2007, SDG&E was in its open season process for the period June 2007 through May 31, 2009. SoCalGas is also in the process of conducting a capacity open season for customers served by its Rainbow Corridor pipelines for the same term as SDG&E's open season.

Table 7 represents SDG&E's most recent demand forecast under the planning criteria stipulated by the CPUC. SDG&E's demand forecasts, however, do not typically distinguish between non-core firm and interruptible service. Consequently, for this capacity assessment, SDG&E has assumed all future non-core commercial and industrial (C&I) and electric generation customers will elect firm non-core service and that such customers would need to be curtailed for a 1-in-35 year cold day demand event. For electric generation, both the total expected peak-day electric generation demand, as well as the portion of that demand with firm entitlements is shown. The firm portion of the electric generation demand is based on the results of the most recent capacity open season, held constant beyond the open season term of 2011/2012.

Table 7: SDG&E Forecasted Peak Demand

SDG&E Long-Term Natural Gas Demand Forecast								
	1-in-35 Year Cold Day Demand(MMCFD)				1-in-10 Day Cold Day Demand (MMCFD)			
Operating Year	Core	Non-Core C&I	EG	Total	Core	Non-core C&I	EG total/firm	Total/Firm
2007/2008	441	0	0	441	418	74	157/110	649/602
2008/2009	447	0	0	447	423	75	154/110	652/608
2009/2010	451	0	0	451	427	75	172/110	674/612
2010/2011	457	0	0	457	433	75	169/61	677/569
2011/2012	463	0	0	463	438	76	164/61	678/575
2012/2013	467	0	0	467	442	76	175/61	693/579
2015/2016	482	0	0	482	457	77	151/61	685/595

Source: Gas Capacity Planning and Demand Forecast Semi-Annual Report filed with CPUC on May 4, 2007

For the forecast period, SDG&E has ample capacity to meet its core peak design day requirements. According to SDG&E, preliminary results of the open season for the Rainbow Corridor indicate SDG&E will have sufficient transmission capacity to meet the firm non-core demand at least through the 2008/09 operating season. After that timeframe, SDG&E does not have sufficient capacity to meet the 1-in-10-year peak design day criteria for its forecasted electric generation (EG) requirements.

Planned and Potential Changes to the SDG&E Natural Gas System (Before Costa Azul LNG)

In November 2006, SoCalGas filed testimony with the CPUC regarding capacity on the Rainbow Corridor. Currently, two customers are planning to construct new electric generation along the Rainbow Corridor. The Inland Empire Energy Center is under construction by GE and was scheduled to begin commercial operation in May 2008. Also along the Rainbow Corridor, a peaking plant is scheduled to begin operation in early 2008. If either one of these facilities elected to receive firm service, capacity along the Rainbow Corridor would be reduced to approximately 585 MMcfd.[45] For the 2008/2009 winter season, this level of capacity would be insufficient to meet the 1-in-10-year peak design day criteria established by the CPUC. A preliminary analysis of SoCalGas' most recent open season indicates this is no longer an immediate concern. There is an ongoing concern that any new request for non-core firm service by an electric generator along the Rainbow Corridor or on the SDG&E system will require system upgrades or operational changes to prevent the need to prorate firm service.

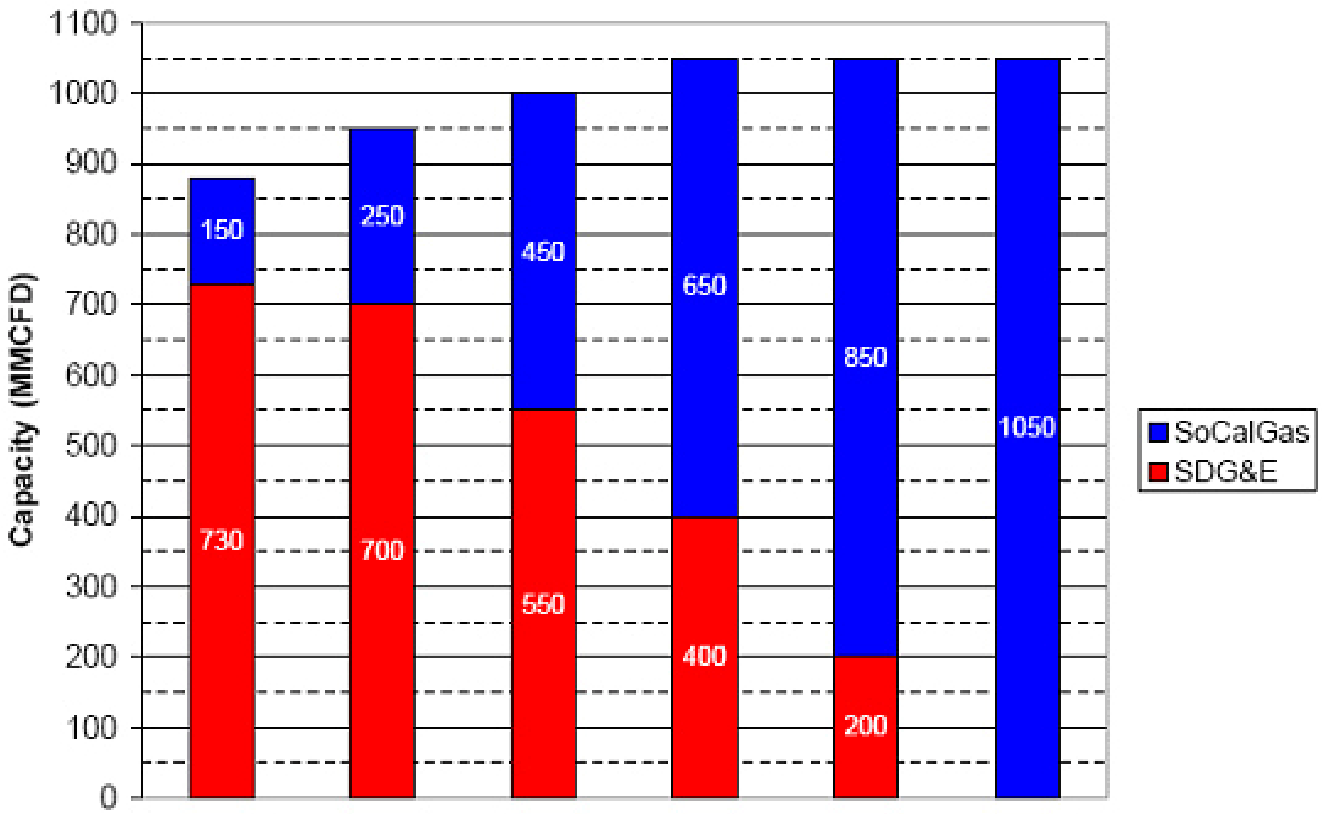
In R.04-01-025, SoCalGas and SDG&E identified that the capacity of the SDG&E system could be expanded by 50 MMcfd year-round by installing 25 miles of 36-inch-diameter pipe between Rainbow Station and Escondido. A preliminary estimate of the cost of this upgrade was $115 million. In addition, it may also be possible to construct an additional pipeline between Moreno Station and Rainbow Station. This option, however, will require additional rights of way and would likely be more expensive than a pipeline from Rainbow Station to Escondido.

Another option identified by SDG&E is to deliver gas directly to the San Diego load center through Otay Mesa. The effect of such a delivery is captured in Figure 12, which is identical to Figure 11 except that a firm 50 MW delivery into SDG&E is assumed at Otay Mesa. Comparing similar scenarios from these two figures shows that firm delivery from Otay Mesa into SDG&E releases additional capacity on the SoCalGas system between Moreno and Rainbow Stations. The maximum benefit occurs at a SoCalGas delivery level of 700 MMcfd to SDG&E, where total deliverability south of Moreno increases to 950 MMcfd in Figure 12 as compared to 750 MMcfd in Figure 11. This 200 MMcfd increase in capacity would be enough to supply at least one of the new power plants currently under construction near Moreno. Furthermore, Figure 12 demonstrates that firm deliveries to SDG&E from Mexico at Otay Mesa can be leveraged to create additional benefits in Southern California. This is true whether the gas delivered to SDG&E at Otay Mesa originates at the Costa Azul LNG terminal, or is delivered by displacement from Blythe. For example, gas flowing to Blythe could flow into North Baja (NBP), then into the Gasoducto Baja Norte (GBN) system and, finally, to Transportadora de Gas Natural de Baja Norte (TGN) for delivery to SDG&E at Otay Mesa.

---

[45] Testimony of David M. Bisi of San Diego Gas & Electric in A.06-10-034 filed October 27, 2006, with the California Public Utilities Commission.

Figure 12: Moreno-Rainbow Corridor vs. San Diego, with 50 MMcfd Supply from Otay Mesa



Source: Testimony of David Bisi of SoCalGas filed on October 27, 2007, before the CPUC

Potential Impacts of the Costa Azul Liquefied Natural Gas Project on SDG&E

The Costa Azul LNG terminal will provide a new source of gas originating in Mexico from the regasification terminal near Ensenada and, to the extent significant volumes are flowing out, will reverse the flow of gas on TGN, GBN, and NBP. Sempra LNG has contracted to pay for an upgrade of the TGN connection with SDG&E at Otay Mesa, MMcfd on a firm basis, and up to 400 MMcfd on an interruptible basis.[46] Firm delivery volumes are based on SDG&E's assessment of what can be used reliably under minimum demand and flow conditions on its system.

If 400 MMcfd were delivered to SDG&E at Otay Mesa during the peak winter period, then SoCalGas would likely have the full 1 Bcfd of capacity between Moreno and Rainbow Stations available on a firm basis without any additional pipeline facilities. In addition, the capacity of

[46] Interviews with SoCalGas and Sempra LNG May 29, 2007.

the existing SDG&E transmission system would also be enhanced since a significant quantity of gas would be delivered by TGN directly to high-demand areas in the border region and San Diego.

Allocating firm capacity to customers created by delivering 400 MMcfd at Otay Mesa is, at this time, a high-risk strategy. It is unclear how much volume will be delivered to Costa Azul on a firm basis and how much will flow out on a firm basis. Presumably, CFE has assured that some or all the gas contracts for its current and future needs will be firm; however, the supplier (BP/Tangguh) has diversion rights, which means that it can divert LNG scheduled for delivery to Costa Azul to other higher value LNG markets. The portion subject to diversion is confidential, however, Sempra has stated that "some gas will always flow out of Costa Azul."[47]

Southeastern California Zone

Supply Capacity

SoCalGas serves the Imperial Valley through its Line 6902, which runs from their backbone transmission system in Riverside County, through Niland and terminates near the California/Mexico border at Line 6903. This extends to the border where gas is ultimately delivered into Mexico at Calexico. Line 6902 in the Imperial Valley is potentially a constrained area on the SoCalGas system. The Imperial Valley system is a summer peaking system, primarily from the Imperial Irrigation District's (IID) gas-fired power generation. The system's capacity is 86 MMcfd.[48]

Gas Demand

SoCalGas conducted open season for Line 6902 for firm service commencing in April 2007. Bid packages were sent to 13 customers who are non-core, non-core eligible, or expected to be non-core eligible within the term of the 2007 open season. Four customers bid for non-core firm service, six elected firm service, two elected non-core interruptible service and one (ECOGAS) elected to amend its existing contract by reducing its maximum contract quantity from 25 MMcfd to 20 MMcfd.

Based on the results of the 2007 open season, summer firm demand is expected to exceed the hourly capacity by 10 percent in 2007 and increasing to 30 percent by 2012. As a result of this open season, SoCalGas is planning to expand the capacity of its Imperial Valley system by looping its Line 6902 north from El Centro toward Niland with 22 miles of 24-inch pipe. This

---

47 Ibid.

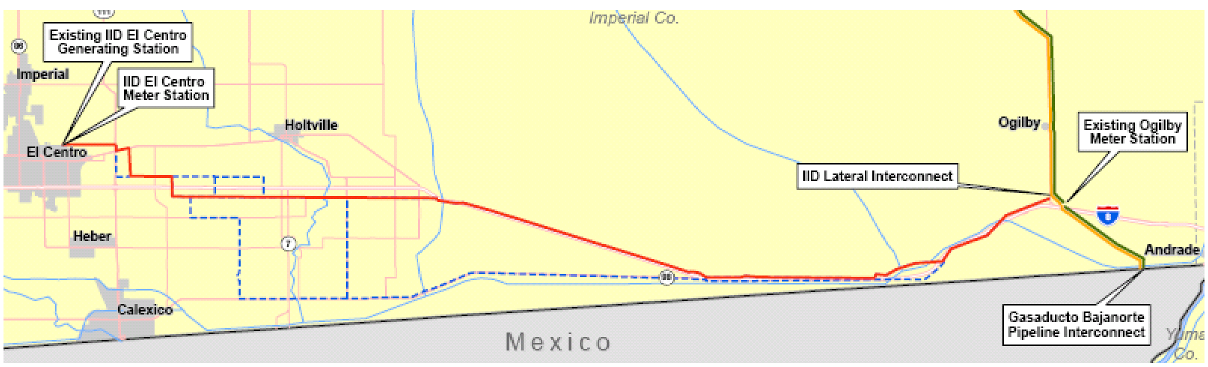
48 Advice Letter AL3474 filed June 1, 2007, with California Public Utilities Commission.

expansion will increase the capacity of that line to 150 MMcfd.[49] This amount is expected to be sufficient to meet firm demand for the next 5 to 10 years.

North Baja Pipeline Expansion in the Imperial Valley

As part of the NBP planned expansion to deliver LNG volumes from Costa Azul, it has also applied for a certificate to construct a 46-mile lateral from its Ogilby Meter Station in the Imperial Valley to the IID El Centro Generating Station. This line will be capable of delivering 103 MMcfd.[50] This plant currently receives its natural gas from SoCalGas through its Imperial Valley system. Figure 13 is a map of the proposed lateral expansion to serve the IID. Through constructing this lateral, IID would be able to receive deliveries of either LNG-sourced gas or domestic natural gas supplies from the El Paso system. Even if LNG-sourced gas is flowing north from NBP into the El Paso system, domestic supplies can be delivered to IDD through this lateral by displacement as long as sufficient LNG-sourced supply is being nominated for delivery to El Paso.

Figure 13: NBP Proposed IID Interconnect



Source: North Baja Pipeline filing at the FERC in CP06-61-000

Baja California

Table 8 shows the forecast of growth in average daily demand for natural gas in the Baja California region through 2015 (peak demand may run 400-500 MMcfd).

[49] Advice Letter AL3474 filed June 1, 2007, with California Public Utilities Commission.
[50] North Baja Pipeline filing with the United States Federal Energy Regulatory Commission CP06-61.

Table 8: Baja California Natural Gas Demand (2005-2015)

Baja California Natural Gas Demand 2005-2015 (MMCFD)	2005*	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Electric Generation	237	248	259	270	282	289	297	301	306	304	303
Industry, including self generation	11	11	12	15	18	18	19	19	20	21	21
Residential, service and transport	1	1	1	1	1	1	1	1	1	1	1
Total	249	260	272	286	301	308	317	321	327	326	325

(*) Actual

Source: Prospectiva del Mercado de Gas Natural 2006 - 2015, SENER, Cuadro A.3.1-Demanda nacional de gas natural por estado, 1995-2015, Anexo 3

The BCN region is served principally by the NBP-GB-TGN pipeline system. Growth in natural gas demand is expected to average 3.1 percent per year over this period, with more than 99 percent of that growth expected to be from industrial (including self-generation of electricity) and electric generation demand. Electric generation alone comprises more than 85 percent of the total expected gas demand growth in the region.

The BCN region is forecasted to add 1,543-MW natural gas-fired power generation through 2016. About 1,048 MW of this additional capacity is for peak day demand and the remaining 495 MW is intended to maintain CFE's planning reserve. The 1,543 MW of new generation will result in additional gas demand of approximately 300-325 MMcfd in the BCN region.[51] Given the current direction of gas flows on these systems from the United States into Mexico, the NBP-GBN-TCN system would have to be expanded (and potentially pipelines feeding NBP) to support the planned electric generation growth in the region.

Currently, all of the gas supply for Baja California is U.S-sourced supply. The vast majority of supply entering Baja California is delivered via the NPB-GBN path. ECOGAS, the local distributor for Mexicali, received approximately 5 percent of the total supply delivered into Mexico in 2006. ECOGAS' supply is delivered through the SoCalGas Imperial Valley system. Finally, an insignificant volume was also delivered to the TGN system at Otay Mesa by SDG&E.

The capacity of the NBP-GBN system is 500 MMcfd while the capacity of the line serving Mexicali from Calexico is 29 MMcfd. There is approximately 25 MMcfd of unsubscribed capacity on the NBP-GBN system.[52] The NBP-GBN-TGN system is a summer peaking system because of the proportionately high demand for gas-fired power generation. Demand on this system is highly weather sensitive. In 2006, peak day flow on this system was 430 MMcf, which represents approximately 86 percent of the system's capacity.[53] Average throughput was

---

[51] This figure assumes a blended heat rate for planned new generation plants (combined cycle and combustion turbine) for the BCN region in the range of 8,200 – 8,800 Btu/kwh.

[52] North Baja Pipeline – informational postings from website.

[53] North Baja Pipeline "Operational Capacity Baja 2005-2007"

approximately 265 MMcfd. In 2005, peak day flow was 367 MMcf, and average throughput was approximately 235 MMcfd.

Northeastern Baja California

Supply Capacity

Natural gas delivery capacity in the Northeastern Baja California region is composed of the NBP-GBN system and a line from the SoCalGas system at Calexico to Mexicali. Capacity used on the NBP-GBN system for customers located in this region is approximately 357 MMcfd or 73 percent of the total contracted NBP-GBN capacity.

Gas Demand

Virtually 100 percent of the natural gas demand in the Northeastern Baja California region is located in the Mexicali area. ECOGAS is the local natural gas distribution company that provides service to residential and C&I customers in Mexicali. In addition, several large gas-fired power plants are located in the Mexicali area, which is served by the NBP-GPN pipeline.

Gas delivered by the NBP-GBN system to the Mexicali area is used primarily for power generation. There is almost 1,700 MW of installed gas-fired electric generation capacity in this region, with about 75 percent of the power generated by these plants exported to the United States. Based on seasonal load data for 2006, it is estimated that approximately 68 percent of the peak gas demand on the NBP-GBN system was used to serve markets located in this region, and the rest was used to supply generation for export to the United States. Growth in peak power demand for this region is expected to be 717 MW through 2016. It is expected that, during the forecast period, there will be 642 MW of gas-fired generation constructed in this region, increasing electric generation natural gas demand by as much as 110 MMcfd. Based on KEMA's analysis, this amount of additional demand cannot be met reliably from increased Southwest sourced U.S. gas deliveries to GBN alone, and would require at least 60 MMcfd of LNG from Baja. In that case, it may be possible to meet the 110 MMcfd increase in electric generation demand through a combination of Baja LNG and Southwest sourced gas deliveries without any Phase II capacity expansion on GBN.

ECOGAS recently requested a reduction of its contract with SoCalGas. Since ECOGAS has not experienced a peak day anywhere close to its existing contract level of 25 MMcfd and given that small customer status would give ECOGAS somewhat more contracting flexibility, it requested that its contracted quantity be reduced to 20 MMcfd. Based on 2006 seasonal load data, it is estimated that ECOGAS' peak day experienced in 2006 was in the vicinity of 16 MMcf. With the planned expansion of SoCalGas' Imperial Valley system, there should be sufficient capacity to serve ECOGAS demand through the forecast period.

Northwestern Baja California

Supply Capacity

Gas is delivered to the western Baja California region by the NBP-GBN-TGN pipelines principally for CFE power generation facilities in Rosarito and to several self-use pipelines that serve industrial and self-generation loads in the Tijuana area, including Toyota Motor Manufacturing de Baja California. Approximately 134 MMcfd, or 27 percent of the total contracted capacity of the NBP-GBN is contracted to customers located in this region. The capacity of the TGN system, which interconnects with GBN at Tijuana, is 300 MMcfd. The TGN system delivers gas to CFE's Rosarito area generating facilities. Sempra's current contract with CFE which runs from 2008-2022 calls for an average delivery of 130 MMcfd, but allows CFE to take additional delivery if needed to support gas-fired generation expansion.[54]

Gas Demand

In 2006, approximately 32 percent of the peak gas demand on NBP-GBN was experienced in the western Baja California Norte region. Of the approximately 30.2 BCF of annual supply delivered to this region in 2006, all but a small portion was consumed by CFE power facilities in Rosarito. On average GBN delivered about 200 MMcf to self-generation customers and TGN delivered about 100 MMcf through the Otay Mesa interconnection with SDG&E.[55]

---

[54] Interview and documents supplied by officials of Sempra LNG at meeting in San Diego on May 29, 2007.

[55] Aggregated data from *Natural Gas Imports and Exports Quarterly Reports (2006)*, U.S. Department of Energy, Office of Natural Gas Regulatory Activities..

CHAPTER 6: Planned LNG Facilities and Transmission Pipeline Additions in Northern Baja California

LNG Facilities in Northern Baja California

Sempra's Costa Azul LNG Regasification Terminal

The Costa Azul terminal is a new LNG regasification terminal currently under construction and owned by Sempra LNG. The terminal is located on a 400-acre site about 14 miles north of Ensenada, Mexico, and will initially consist of two full-containment tanks and pads for two more. The initial send out capacity will be 1.0 Bcfd with the potential to increase it to 2.5 Bcfd. Sempra held a non-binding open season for additional service from Costa Azul and announced in May 2006 that it had received bids totaling 2.9 Bcfd, more than double the expandable capacity of 1.5 Bcfd. No new information regarding the status of the open season nominations has been made public.

Commercial operation is currently scheduled for 2008. Sempra has contracted for half (500 MMcfd) of the send out capacity and Shell has contracted for the other half. Sempra has also contracted with BP/Tangguh to supply its portion of capacity with LNG from Indonesia and has entered into a long-term contract with CFE to support its future energy requirements in northern Baja California, which includes the existing Presidente Juarez power plant in Rosarito. The contract with the CFE is a 15-year agreement that provides the CFE an average of 130 MMcfd of gas supply with a range of between 40 to 280 MMcfd.[56] Sempra anticipates meeting this obligation with LNG delivered from the Costa Azul terminal.

Phase I of the Costa Azul terminal (and the associated spur to GBN) adds 1 Bcfd of capability to deliver gas into Baja California with only a limited need for pipeline upgrades. Addition of this 1 Bcfd gas supply at Costa Azul will eliminate the need for southbound gas deliveries from the United States to Baja California. In fact, on the basis of pipeline delivery agreements filed with FERC (see Table 10), about half of the Phase 1 gas capacity from Costa Azul will be exported from Baja California to serve the U.S. gas market. This leaves approximately 500 MMcfd of gas supply from Costa Azul for use within Baja California, which is more than sufficient to meet the 2015 forecasted additional summer peak electric demand in Baja California (approximately 300-325 MMcfd). After supplying this projected gas demand, another 175-200 MMcfd will be available during the peak summer months to serve new markets, including potential new power plants in Baja California for export to the United States electric market. Assuming a heat rate for new gas-fired generation in the range of 7500 Btu/kwh, this equates to roughly 1,100

---

[56] Interview and documents supplied by officials of Sempra LNG at meeting in San Diego on May 29, 2007.

MW of electric generation. During the winter months when gas demand in Baja California is significantly lower, more capacity will be available to move gas (or electricity) into California and other U.S. markets.

It should also be noted that year-round availability of the full 1 Bcfd of LNG is an unknown at this time. For example, the Sempra LNG supply contract includes supplier diversion rights which allow deliveries to be diverted to other higher value markets. (It's likely similar provisions are in Shell's LNG contracts.) This may be a disincentive to construction of additional power plants in Baja for export of electric power to U.S. markets using Phase 1 Costa Azul LNG capacity. However, even without the full LNG supply being available, the additional pipeline capacity created in Baja California provides the opportunity to deliver additional Southwest sourced gas supplies into SDG&E via the Baja pipeline system and then into SDG&E's system at Otay Mesa as discussed in more detail below.

Chevron's Proposed Mar Adentro LNG Project

Chevron had proposed a 700 MMcfd LNG terminal off the coast of Tijuana near the Coronado Islands. Although Chevron has issued no formal press release regarding the status of the project, a Chevron spokesperson had indicated that based on its business needs, three key permit applications required to develop the project have been withdrawn. The spokesperson further indicated that the project is no longer aligned with Chevron's equity gas resources.

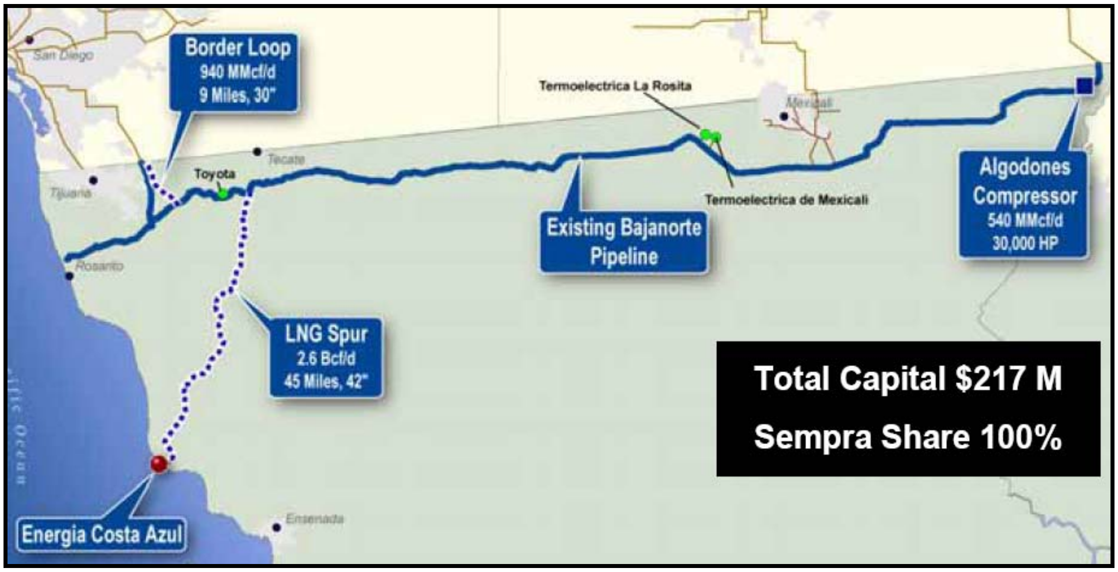
Planned New Pipeline Capacity in Northern Baja

Gasoducto Baja Norte Expansion

In addition to the Costa Azul terminal, a number of changes and additions to the existing pipeline system serving the Baja California region are being planned. Figure 14 shows the planned changes in the Baja California region. A 45-mile LNG spur will be constructed to deliver up to 2.6 Bcfd of regasified LNG from the Costa Azul terminal to the GBN pipeline. This spur will be able to deliver the maximum send out capacity of the expanded LNG terminal. In addition, a second TGN line (the border loop) is planned that will be capable of delivering up to 940 MMcfd into the SDG&E system. As shown in Table 7, this significantly exceeds SDG&E's currently forecasted demand. Unfortunately, the excess capacity available on TGN could not be sent farther north to SoCalGas without significant pipeline expansion through SDG&E.

The GBN system is also being modified to enable gas to flow east and north into the NBP system. Also, 30,000 hp of compression is being added at Algodones, Mexico, that will enable delivery of 540 MMcfd into the North Baja Pipeline. Construction is approximately 25 percent complete on this $217 million expansion.[57] This system will be expanded farther in conjunction with expansion of the Coast Azul send out capacity.

Figure 14: Gasoducto Baja Norte Expansion



Source: Sempra

North Baja Pipeline

The NBP, owned by Trans-Canada, is located in the United States and will continue to operate in an integrated manner with GBN. NBP has filed with the FERC for approval to expand the capacity of the pipeline to deliver the full, expandable send-out capacity of the Costa Azul terminal. NBP proposes to construct this expansion in three phases. Phase I will consist of making the necessary changes to the existing system to allow the reversal of the current direction of flow. This phase will involve modifications to existing meter and compressor stations to enable gas to flow from south to north and be delivered into the El Paso system. In addition, a 2.1-mile lateral and new meter station (Arrowhead) will be constructed to connect with the SoCalGas system at Blythe.

Phase I-A involves construction of a 46-mile lateral from the NBP to the IID El Centro Generating station in El Centro that will be capable of delivering 103 MMcfd for power generation.

Phase II will require the construction of up to 79.8 miles of pipeline loop (B-Line) adjacent to North Baja's existing system (A-Line) between Blythe and the United States/Mexico border. At

---

[57] Presentation by George Liparidis, President & Chief Executive Officer Sempra Pipelines & Storage at Analyst Conference on March 29, 2007.

this date, it remains uncertain what the final Phase II volumes would be. Once the Phase I, Phase I-A, and Phase II expansions are completed, the total northbound capacity of the North Baja system could be as much as 2,753 MMcfd.

Table 10 lists North Baja's shippers that have executed precedent agreements. They are listed by phase, contracted volumes, and delivery path. In addition to the new expansion shippers, several of North Baja's existing shippers have elected to reverse the direction of their existing southbound capacity to northbound capacity. The initial volumes these shippers have elected to flow northbound is 283,570 Mcfd in 2007. In 2010, this volume is reduced to 255,400 Mcfd. Given the capacity of the North Baja Pipeline, it is assumed that only 500 MMcfd of the Phase 1 northbound precedent agreements shown in Table 10 call for firm delivery.

Gas Constraints and Limitations

The Costa Azul LNG facility will have the initial capacity to deliver 1 Bcfd into the GBN, TGN, and NBP systems. Upgrades needed to enable gas to flow in an easterly direction on GBN and north along the NBP system, as well as the 45-mile spur from Costa Azul to GBN and the Border Loop, are expected to be ready when LNG-sourced gas is ready to flow out of the Costa Azul terminal. In addition, the facilities necessary to enable 400 MMcfd of firm deliveries to SDG&E through Otay Mesa are also expected to be completed before Costa Azul commences commercial operation. The expected uses of the NBP system are indicated by the precedent agreements shown in Table 9, which reflects both the initial 2008 LNG capacity and the future Costa Azul LNG expansion phase, circa 2010.

Table 9: North Baja Pipeline Precedent Agreements

North Baja Pipeline Expansion Project Precedent Agreements		
Phase/Shipper	Quantity (Dthd) Annual	Delivery Path
Phase I Northbound		
Coral Energy Resources, LP	212,000	U.S.-Mexico border to El Paso Natural Gas Company [a] (El Paso)
Sempra Energy LNG Marketing Corp.	100,000	U.S.-Mexico border to El Paso [a]
Existing Shippers [b]	302,000	U.S.-Mexico border to El Paso [a]
Total Phase I Northbound	614,000	
Phase I-A IID Lateral		
Imperial Irrigation District	110,000	Ogilby Meter Station to El Centro Generating Station
Phase II Northbound		
Chevron USA, Inc.	1,070,000 [c]	U.S.-Mexico border to El Paso [a]
Coral Energy Resources, LP	530,000 [c]	U.S.-Mexico border to El Paso [a]
Sempra Energy LNG Marketing Corp.	200,000	U.S.-Mexico border to El Paso [a]
Total Phase II Northbound	1,800,000	
Total Northbound Phases (2010)	2,384,000 [d]	
Unsuscribed Northbound Capacity	548,000	

[a] Deliveries to Southern California Gas Company would fall within the path.

[b] Several existing shippers reversed the primary path from southbound to northbound for a total 302,000 Dthd (283.57 MMscfd). In 2010, this volume is reduced to 272,000 Dthd (255.40 MMscfd).

[c] Although these volumes were anticipated to be transported from the Mar Adentro terminal, the shippers have not terminated their precedent agreements for transportation capacity on Phase II of the North Baja Pipeline Expansion Project.

[d] Reflects the reduction in Phase I volumes described in footnote b.

Note: All precedent agreement terms are for 20 years.

Source: Final Environmental Impact Statement on North Baja Pipeline Expansion Project, Docket Nos. CP06-61-000 filed at the FERC on June 8, 2007

Given the location of the LNG-sourced supply relative to the gas markets in the region, these initial upgrades will provide a significant increase in the ability of the TGN-GBN system to serve existing and new gas markets in the northern Baja California region.

The new LNG spur that will receive gas directly from the Costa Azul terminal will have a capacity of 2.6 Bcfd. It will interconnect with the GB system just east of the Toyota manufacturing facility, where gas will flow both in an easterly direction toward Mexicali and in a westerly direction toward Rosarito. The initial upgrades on NPB, GB, and TGN are expected to enable full utilization of the 1 Bcfd of send-out capacity of the LNG terminal. Approximately 500-550 MMcfd will be able to flow eastward, with the remainder flowing westward for delivery to SDG&E, industrial customers, and the CFE power plants in Rosarito. In addition, a planned 279-MW power plant (with a peak natural gas demand of 45 to 50 MMcfd) in Ensenada, Mexico, which is close to Costa Azul, would most likely be served directly off the new LNG spur. This capacity is sufficient to serve the total projected natural gas demand for the region (including electric generation) through 2016.

Concerning sources of LNG supply to Costa Azul, Sempra has contracted with BP/Tangguh for an annual volume of 3.7 million tonnes (or more than 190 Bcf), which is the equivalent of about 530 MMcfd. The contract currently calls for delivery of these volumes starting in late 2008. The supplier, however, has the right to divert some portion of that supply to other markets. The details of those diversion rights have not been made public. Presumably, all or a portion of the supply contract with CFE is a firm supply, but it is unclear what portion of the remaining supply, if any, will be delivered to Costa Azul on a firm basis.

Shell has contracted for the remaining 500 MMcfd of send-out capacity at Costa Azul. For its portion of the capacity, Shell had announced that it planned to deliver LNG supply from its Sakhalin II project in Russia and from the Gorgon project in Australia. In October 2004, Shell announced an agreement to supply 37 million tons of LNG over a 20-year period to the Costa Azul terminal from the Sakhalin II project. Shell also announced in April 2005 that its Gorgon project would supply up to 2.5 million tons of LNG per year to Costa Azul. Recently, however, Gazprom, the Russian state natural gas company, has taken majority ownership of the project. This change in ownership occurred after reports of significant environmental violations by Shell and a suspension by Russia of its permits. At this time, it is unclear how (or if) this change in ownership, as well as the delays experienced, will affect the delivery of this supply to Costa Azul. The Gorgon project, originally scheduled to begin producing LNG by 2010, is now expected to produce LNG no earlier than 2012, with 2014 a more likely timeframe.

Market dynamics would suggest supply should always be available if the price offered is high enough. (Korea Gas Corporation of South Korea reportedly paid as much as $26 per Mmbtu in 2005 and 2006 when it faced steep competition for winter cargoes.) The long lead time and high capital cost to construct liquefaction facilities, the growing number of import terminals, and potential shipping issues create some risk of LNG supply shortages and/or unacceptably high prices. However, given the generally lower global demand for LNG during the summer, it is expected that adequate LNG will be available to meet or exceed Baja California's summer peaking electric demand at reasonable cost.

CHAPTER 7: Regulatory Proposals and Government Directives That Could Stimulate or Facilitate Infrastructure Expansion in the Border Region

National Interest Electric Transmission Corridors

The Energy Policy Act of 2005 (EPAct) has for the first time given the United States Government the statutory authority to act on the siting and permitting of transmission projects that are deemed to be "in the national interest." As the Edison Electric Institute states,…"(The) EPAct creates a new Section 216 of the Federal Power Act, providing a set of critically important siting and permitting provisions to support new transmission investments by improving the efficiency of the permitting process."[58]

The new statute permits the United States Department of Energy (DOE) to identify a number of National Interest Electric Transmission Corridors (NIETCs) where the need for new transmission is critical. Based on the results of a mandated study of electric transmission congestion, the Secretary of Energy may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects customers as a national interest electric transmission corridor."[59] Line permitting and certification would still begin at the state level but, in the case of lines located within such NIETC corridors, FERC can exercise its new authority for "projects where transmission capacity needs have been established, but lengthy litigation or federal permitting causes unreasonable and costly delays of formal approval."[60]

In its 2006 Transmission Congestion Study, DOE identified Southern California as an area with critical transmission congestion and cited four transmission projects that it claims are needed in the near future, including:

- Palo Verde – Devers No.2.
- Sunrise Powerlink.
- Tehachapi Transmission Phase I.
- Imperial Valley Transmission Upgrade.

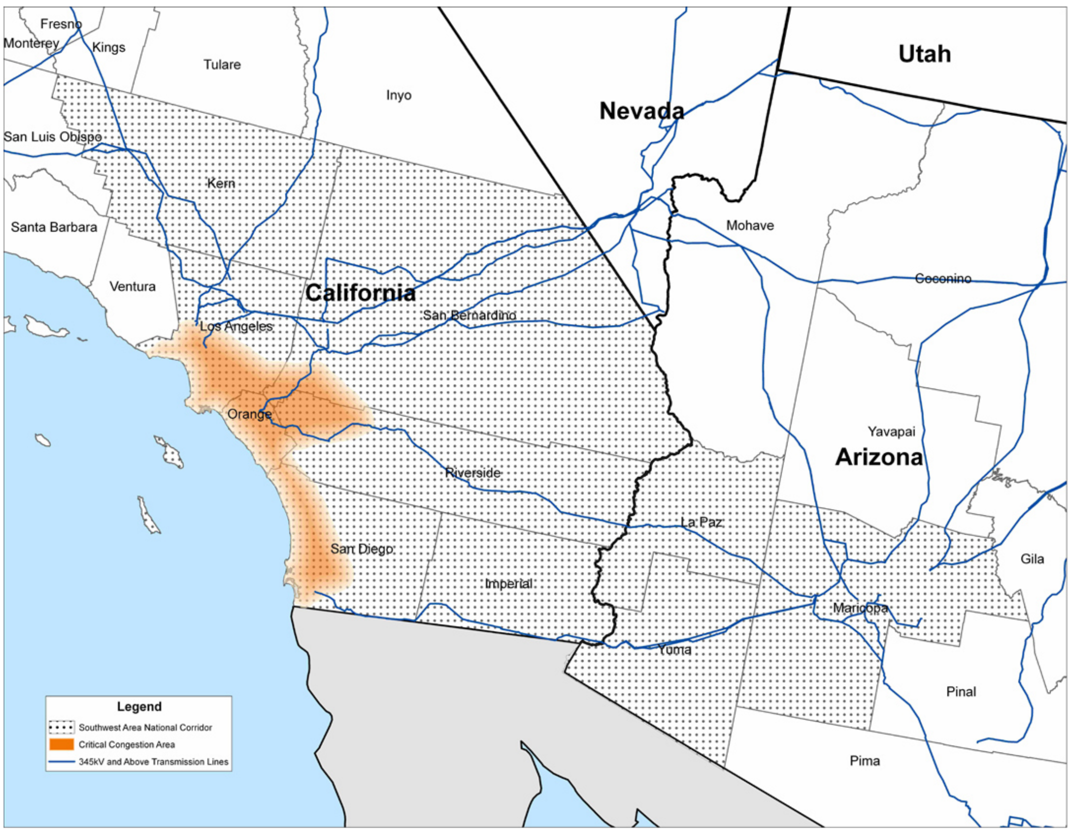
---

[58] Edison Electric Institute's letter to Kevin Kolevar, Director, Office of Energy Delivery and Electric Reliability, United States Department of Energy, October 10, 2006.
[59] United States Department of Energy, *National Electric Transmission Corridor Congestion Study*, Washington, District of Columbia, August 2006.
[60] Edison Electric Institute Letter to United States Department of Energy, October 10, 2006.

However, the 2006 study stopped short of defining a National Interest Electric Transmission Corridor in Southern California, or elsewhere.

Subsequently, in May 2007, the DOE proposed two NIETC corridors including the "Draft Southwest Area National Corridor." The boundary of the Southwest Area National Corridor was finalized by DOE Order in October 2007.[61] The area encompassed by the corridor is shown in Figure 15. This corridor was finalized by the Department of Energy on March 6, 2008.[62] The southern boundary of this corridor follows the United States/Mexico border from a point south and west of Phoenix, Arizona, to the Pacific Ocean at the southern edge of San Diego, California. It includes seven counties within California (Imperial, Kern, Los Angeles, Orange, Riverside, San Bernardino, and San Diego) and three counties in Arizona (La Paz, Maricopa, and Yuma).

Figure 15: Southwest Area National Corridor Map



Source: United States Department of Energy, 2007.

---

[61] *National Electric Transmission Congestion Report*, United States Department of Energy Order 6450-01-P, 2 October 2007, pp. 129-131.

[62] *National Electric Transmission Congestion Report*, United States Department of Energy Order denying all applications for rehearing and requests for stay in 72 FR 56992, March 6, 2008.

Such designation of the Southwest Area as a National Interest Electric Transmission Corridor has the potential to significantly affect energy infrastructure expansion in the California/Mexico border region. While FERC has no authority to permit lines in Mexico, it could now have the authority to do so for the U.S. portions of any lines in the border region that it deems necessary to relieve the transmission congestion that exists in a broad area of Southwestern California. To the extent that such lines facilitate deliveries of low-cost electricity to the region and state regulators fail to license the project promptly, FERC could intervene to approve line siting and permitting. A potential candidate for such FERC intervention is the Devers – Palo Verde No. 2 (DPV2) line, which has a proposed corridor located within the geographic boundary of the Southwest Area National Corridor. DPV2 has already been approved by the California Public Utilities Commission, which also found it would increase transfer capability into California, but the line was denied a Certificate of Environmental Compatibility by the responsible Arizona regulator.[64] In response to Arizona's licensing decision, Southern California Edison advised the Arizona regulator in February 2008 that they were initiating a pre-filing process with the FERC under authority granted to the FERC under the siting provision of the EPAct for such interstate lines.[65]

The California State Legislature has also addressed the corridor planning issue through Senate Bill 1059, which charges the Energy Commission with the task of identifying the long-term needs for electrical transmission corridor zones within the state and integrating corridor planning at the state and local levels. The Commission has been addressing this responsibility both in its preparation of the *2007 Integrated Energy Policy Report* (Docket No. 06-IEP-1F) and through formulating proposed regulations governing the transmission corridor designation process in California (Docket No. 07-OIR-1). Furthermore, the Commission is participating in the development of a West-Wide Energy Corridor Programmatic Environmental Impact Statement along with the Western Electricity Coordinating Council.

The current focus on electric corridor needs at the federal, state, and local levels is unprecedented and offers an exciting opportunity to provide for the future energy needs of the California/Baja California Norte border region. It is imperative that the Commission maximize this opportunity by establishing the corridor designations needed for long-term electric infrastructure expansion needs in the border region.

Effects of FERC Order 890

On February 16, 2007, FERC issued Order No. 890, requiring that "…transmission providers implement a coordinated, transparent and participatory transmission planning processes as a

---

[64] Ibid., p. 87.

[65] Letter from Ronald L. Litzinger, Senior Vice President, SCE to the Arizona Corporation Commission, dated February 25, 2008.

means to alleviate perceived opportunities for undue discrimination." FERC considers these rules to be an amendment to its prior regulations and pro form open access transmission tariff (OATT) adopted in earlier Order Nos. 888 and 889. According to FERC, these orders "…encouraged utilities to engage in joint planning with other utilities and customers and to allow affected customers to participate in facilities studies to the extent practicable."[66] However, the prior orders "…did not, require that transmission providers coordinate with either their network or point-to-point customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans. The Commission also did not require joint planning between transmission providers and their customers or between transmission providers in a given region."[67]

Where ISOs and RTOs exist, they are required to participate in these processes, as well, but FERC explicitly stipulates that "…transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process." FERC clearly stated this point because it felt RTO planning processes tended to emphasize regional, rather than local, problems and solutions. Further, FERC noted that some participants in the rulemaking process felt that RTOs and ISOs did not carefully scrutinize individual transmission owner's plans before including them in the regional plan.

The relation between FERC's 890 provisions and California/Mexico border energy issues may not be evident on the surface. However, when one examines the types of participants FERC intends to involve more fully in the planning process, the relevance becomes clear. Specifically, FERC requires an active role for local and regional customers, competitors, and state commissions. These include load-serving entities, such as Southern California industrial customers, independent power producers, large electricity consumers, and other utilities. All of these entities are transmission users and may present quite different reactions to congestion on a given transmission owner's system. Increased access to potentially lower-cost electric resources in the border region, whether renewable or conventional, is expected to be a common priority for stakeholders and regulators.

The California ISO and California utilities need to address FERC's 890 requirements through compliance tariff filings demonstrating how they will meet the requirements for stakeholder participation in electric transmission planning processes. The Energy Commission and other stakeholders with a vested interest in the border region have the opportunity to take an active role in these proceedings in order to ensure their views on these processes are heard.

---

[66] Federal Energy Regulatory Commission, Order No. 890, Final Rule: *Preventing Undue Discrimination and Preference in Transmission Service*, Paragraph No. 420, Washington, District of Columbia, February 16, 2007.
[67] Ibid.

United States and Mexican Regulations Regarding Energy Export

The trajectory of the infrastructure scenarios envisioned in this study would increase the flow of energy from Mexico into California. In that regard, Mexican regulations regarding energy export have been addressed in some detail in a recent report.[68]

It is unclear at this time if the development of energy infrastructure in the California/Baja California Norte border region could also entail additional exports of electric energy from the United States to Mexico. The Federal Power Act, Section 202(e), Part ll requires that no person may export electric energy from the United States to a foreign country without first obtaining authorization from the U.S. DOE. Part II, Section 202(e) states that exports of electric energy should be allowed unless the proposed export would impair the sufficiency of electric power supply within the United States or would impede or tend to impede the coordinated use of the U.S. power supply network. Based on these guidelines, DOE will grant authorization to export electric energy only if it is determined that:

- Sufficient generating resources exist such that the exporter could sustain the export while still maintaining adequate generating resources to meet all firm supply obligations.
- The export would not cause operating parameters on regional transmission systems to fall outside established industry criteria.

In addition, DOE must also comply with NEPA before granting authorization to export electric energy. However, in many instances DOE is able to cite a categorical exclusion (10 CFR 1021.410) for exports over existing international transmission lines. Ultimately, DOE will issue an export authorization to the last entity that holds title to electricity inside the United States to export the electricity using a specific transmission line or collection of lines.

Future Regulatory Proposals and Governmental Options

While regulators and government agencies cannot control the behavior of private investors, appropriate public policy and regulations can help to guide private investment in an appropriate direction and eliminate roadblocks to development of necessary infrastructure expansion. In that regard, it is expected that the next phase of KEMA's current study for the Energy Commission will surface additional recommendations on regulatory and governmental options that could stimulate and/or promote beneficial infrastructure expansion in the border region.

---

[68] *Challenges and Opportunities to Deliver Renewable Energy from Baja California Norte to California*, Consultant Report, California Energy Commission, CEC-600-2008-004, June 2008.

CHAPTER 8:
Conclusions and Action Items

For Natural Gas Facilities:

Conclusion:

The completion of liquefied natural gas (LNG) terminal and storage facilities currently under construction in coastal Baja California will facilitate the export of natural gas from Baja California, as well as expansion of natural gas-fired generation in Baja California. For example, the initial Costa Azul design capacity of 1 Bcfd will accommodate approximately 500 MMcfd of exports to the United States, as well as 500 MMcfd of deliverability into Baja California. This amount is sufficient to meet the 2015 forecasted summer peak demand in Baja California (approximately 300-325 MMcfd) and still leaves 175-200 MMcfd during the peak summer months to either support new generation development or serve other gas markets such as California. This 175-200 MMcfd surplus equates to roughly 1,000 MW of new power plant capacity.

Action Items:

A) Given the extent to which California and Baja California electric generating resources may rely on overseas LNG supplies in the future to meet peak electric demand, California and Mexico regulators may wish to consider the reliability and competitiveness of related fuel supply contracts during the licensing of future gas-fired power plants in the border region.

B) The State of California should consider potential benefits of expanding long-term corridor designation planning processes to include corridors for high-pressure gas pipelines, such as those that may be needed to support future electric generation expansion in the California/Baja border region.

For Electric Transmission:

Conclusion:

At present there is insufficient electric transmission on either side of the border to export as much as 1,000 MW of new electric generation from Baja California that could be fueled by Phase 1 of the LNG expansion. Some firm deliveries could be made northbound over the existing Path 45 facilities, but they would need to compete with other resources for delivery to load centers given the congestion constraints north of the border. The following actions would help to mitigate this transmission constraint.

Action Items:

The Energy Commission should include the following border region electric transmission projects in its 2007 Strategic Transmission Investment Plan:

- SDG&E's "Sunrise Powerlink" Project.
- LADWP's "Green Path North" Project.
- IID's "Indian Hills – Devers 2" 500-kV line (including associated lower voltage upgrades).
- SDG&E's Jacumba Area 500/230-kV Renewable Collector Substation.

A) The identification of essential electric transmission corridors in the border region is vital to future development of energy infrastructure in the region. All opportunities to achieve this strategic objective should be explored under DOE's National Interest Electric Transmission Corridor initiative and California Senate Bill 1059. The current focus on electric corridor needs at the federal, state, and local levels is unprecedented and provides an opportunity to provide for the future energy needs of the California/Baja California Norte border region. The Commission can maximize this opportunity by establishing the corridor designations needed for long-term electric infrastructure expansion needs in the border region, possibly including a "Full Loop" 500-kV path through SDG&E connecting into SCE's 500-kV system.

B) The Energy Commission and other stakeholders with a vested interest in the border region should consider taking an active role in the compliance filings by California ISO and California utilities regarding FERC 890 transmission planning processes to ensure their views on these processes are heard.

Regarding Pending Investigation

Further electric and gas transmission corridor needs can be expected to surface during the next phase of study work that KEMA is performing for the Commission. That investigation will consider further LNG expansion beyond Phase 1 of Costa Azul and will identify and compare possible options/scenarios for energy infrastructure development in the border region, including:

- Additional development of LNG in Baja California as a source for new gas-fired generating plants in the border region.
- Development of gas-fired electric generation in Baja with new electric transmission lines to export the energy to California.
- Development of gas-fired electric generation in the border region of California, with new cross-border gas pipelines to supply fuel for the plants.

GLOSSARY

BC - Baja California

Bcf(d) - Billion cubic feet (per day)

BCN - Northern Baja California

BCP - Baja California Power

California ISO - California Independent System Operator

CC - Combined-cycle

CFE - Comisión Federal de Electricidad

C&I - Commercial and industrial

CPCN - Certificate of Public Convenience and Necessity

CPUC - California Public Utilities Commission

DC - Direct current

DOE - Department of Energy

DPV2 - Devers-Palo Verde No. 2

Dthd - Dekatherms per day

EG – Electric Generation

FERC - Federal Energy Regulatory Commission

GB - Gasoducto Bajanorte

GCT - Gas combustion turbine

IEPR - Integrated Energy Policy Report

IID - Imperial Irrigation District

IV - Imperial Valley

kV - Kilovolt

LADWP - Los Angeles Department of Water and Power

LEAPS - Lake Elsinore Advanced Pumped Storage

LNG - Liquified natural gas

ML - Miguel

Mmbtu – Million British thermal units

MMcfd (MMscfd) - Million cubic feet per day

MW - Megawatt

NBP - North Baja Pipeline

NEPA - National Energy Policy Act

NIETC - National Interest Electric Transmission Corridor(s)

OATT - Open Access Transmission Tariff

POISE - Programa de Obras e Inversiones del Sector Eléctrico

PPA - Power purchase agreement

ROA - La Rosita

RTO - Regional transmission organization

SCE - Southern California Edison

SDG&E - San Diego Gas & Electric Company

SES - Sterling Energy Systems

SLRC - San Luis Rio Colorado

SoCalGas - Southern California Gas Company

SONGS - San Onofre Nuclear Generating Station

SWPL - Southwest Powerlink

TDM - Termoelectrico de Mexicali

TE/VS - Talega-Escondido/Valley-Serrano

TGN - Transportadora de Gas Natural de Baja California

TJ - Tijuana

WECC – Western Electricity Coordinating Council

APPENDIX A: Supplemental Information on Renewable Resources in Northern Baja California

Geothermal Resources

Geothermal capacity in Northeastern Baja California for the 2007-1016 CFE planning horizon is limited to the existing 720 MW plus the additional 25 MW scheduled to go online in 2010. Prior assessments for geothermal energy potential in the area carried out on behalf of the Commission indicate that additional short-term potential for this resource in Baja California may be limited to the binary cycle heat recovery of the hot brine effluent from Cierro Prieto generating facilities. This potential has been estimated at 245 MW.[69]

The electric demand-resource analysis for the Baja California control area, as discussed in the body of this report, indicates that peak capacity requirements and reserve margins will barely be met through the planning horizon. Even so, a preliminary annual load factor analysis of the planned natural-gas-fired plant additions in Baja California indicates that utilization of CFE's combined-cycle generating facilities in the region will be lower than desirable. It may be possible to increase the load factor of these combined-cycle plants and free up some Cerro Prieto geothermal energy for export to California under the RPS program. The economics of such a concept would depend on to a large extent on natural gas prices and the amount of dissimilarity between load patterns and resulting dispatch prices in Baja California and California. As a minimum, the feasibility of this idea should be further explored.

Hydro Resources

While the Baja California climate is generally characterized by limited precipitation, its Northwestern zone has limited hydroelectric energy potential. CFE has identified two potential sites for pumped hydroelectric plants with a 1,200-MW capacity and 2,504-MWh annual average energy production.[70] These projects have a capacity of 600 MW each, to be built on existing dams near Tijuana and Tecate. Both projects are in the pre-feasibility stage.

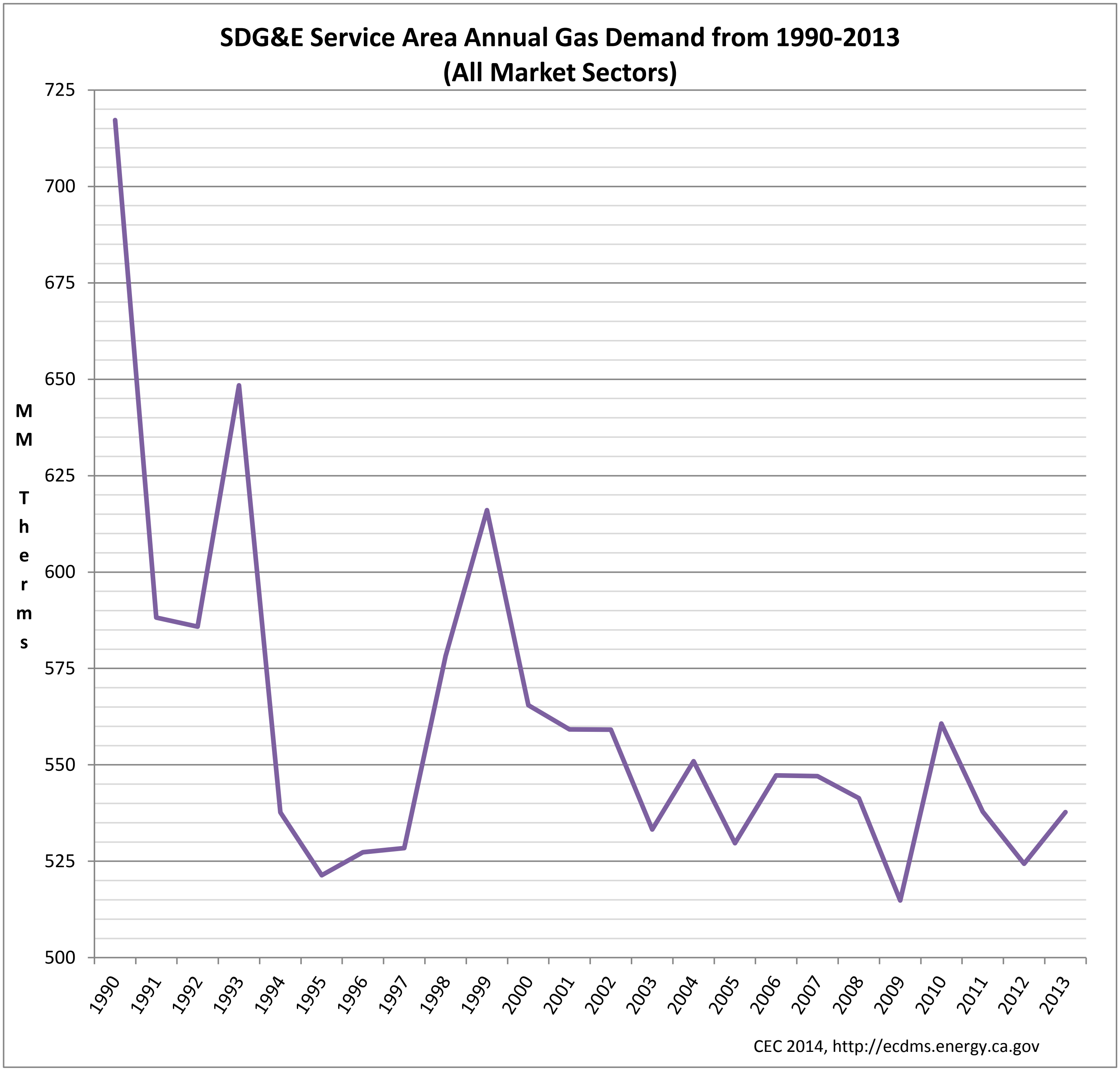
---

[69] *Energy Supply and Demand Assessment for the Border Region*, Consultant Report, California Energy Commission, CEC-600-2005-023, May 2005, p. 19.

[70] *Programa de Obras e Inversiones del Sector Eléctrico 2007-2016*, Cuadro 3.6, p. 3-12.

See 8/10/15 email on page 2, below.

In addition, refer to the following chart prepared from the data at http://ecdms.energy.ca.gov



From: Peterson, Robert
Sent: Friday, July 24, 2015 4:51 PM
To: de Llanos, Estela
Cc: Anne Marie McGraw; Blessent, Beverly; Navin, Neil; Farrell, Peggy; Karpowicz, Ron; Salazar, Jeff; Borak, Mary Jo
Subject: RAIN 3602: Comments Set 1 (Pre-File PEA Chapter 2: Project Purpose and Need/Project Objectives)

Estela and Team,

Instead of waiting to send a big package of comments, I decided to send this off today. My next series of comments will address the project description and specific alternatives.

Pre-File PEA Chapter 2: Project Purpose and Need/Project Objectives
The PEA does not provide sufficient justification for the proposed capacity increase of 200 MMcfd. Further data will be necessary to ensure that a reasonable range of alternatives can be i dentified and to determine whether each alternative meets the project's basic objectives. Further data will also be needed to sufficiently document the project's underlying purpose.

As noted in the CEC's California Energy Demand 2014-2024 Final Forecast (CEC 2014, p. 69, Table 20), natural gas demand in SDG&E's service territory has reduced by more than 200 MM therms since 1990 (about 28 percent) and is expected to further reduce through this year. The following table or similar should be updated based on 2015 historical values for inclusion in the PEA. A discussion should also be provided.

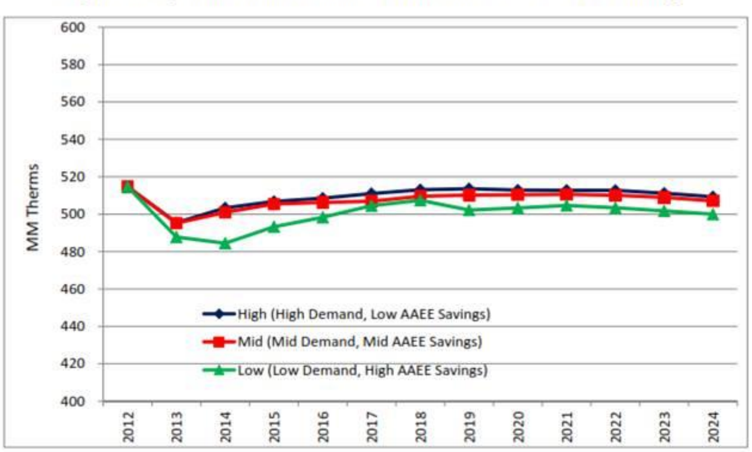
Table 20: SDG&E Baseline Natural Gas Forecast Comparison

	Consumption (MM Therms)			
	CED 2011 Mid Case	*CED 2013 Final High Energy Demand*	*CED 2013 Final Mid Energy Demand*	*CED 2013 Final Low Energy Demand*
1990	717	717	717	717
2000	565	565	565	565
2012	580	515	515	515
2015	609	508	507	495
2020	665	524	524	522
2024	--	530	535	541
	Average Annual Growth Rates			
1990-2000	-2.35%	-2.35%	-2.35%	-2.35%
2000-2012	0.22%	-0.78%	-0.78%	-0.78%
2012-2015	1.62%	-0.43%	-0.51%	-1.28%
2012-2022	1.69%	0.26%	0.31%	0.34%
2012-2024	--	0.24%	0.32%	0.41%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

With the inclusion of Additional Achievable Energy Efficiency (AAEE) savings, the CEC does not forecast that natural gas demand will exceed 2012 levels in the next 10 years (CEC 2014, p. 75, Figure 36). Demand would equate to between -0.09 percent and -0.24 percent through 2024. The following chart or similar should be updated based on 2015 data for inclusion in the PEA. A discussion should be provided.

Figure 36: Adjusted Demand Scenarios for Natural Gas, SDG&E Service Territory



Source: California Energy Commission, Demand Analysis Office, 2013

Joff Morales
Regulatory Affairs
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 858-650-4098
JMorales@semprautilities.com

April 14, 2014

PUG 100
I.00-11-002

Mr. Edward Randolph
Director – Energy Division
California Public Utilities Commission
505 Van Ness Avenue, 4-A
San Francisco, CA 94102

Re: Gas Capacity Planning and Demand Forecast Semi-Annual Report

Dear Mr. Randolph,

Pursuant to California Public Utilities Commission Decision 02-11-073 in the Gas Transmission OII (I.00-11-002), SDG&E hereby submits the attached semi-annual report on its gas system capacity planning and demand forecasts.

If you have any questions, please contact Joff Morales at (858) 650-4098.

Sincerely,

Joff Morales
Regulatory Affairs

Enclosures

cc: Greg Reisinger, Energy Division

SAN DIEGO GAS & ELECTRIC COMPANY
GAS CAPACITY PLANNING AND DEMAND FORECAST
SEMI-ANNUAL REPORT

Pursuant to Ordering Paragraph 9 of California Public Utilities Commission (CPUC or Commission) Decision No. ("D.") 02-11-073[1] (issued November 21, 2002 in I.00-11-002), San Diego Gas & Electric Company (SDG&E) hereby submits its semi-annual report on its gas system capacity planning and demand forecasts.

This report addresses the adequacy of the SDG&E gas transmission system to meet the forecast of incremental gas demand, and whether that growth in gas demand would cause SDG&E the need to add incremental gas transmission capacity, within the confines of the process adopted by the Commission in D.02-11-073, i.e. using the firm service requests obtained during regular capacity open seasons, along with traditional demand forecasts, to signal whether additional capacity is needed. SDG&E and Southern California Gas Company (SoCalGas) are actively exploring whether this process still provides a reliable benchmark for capacity needs in San Diego.

I. EXECUTIVE SUMMARY

SDG&E system capacity continues to meet the 1-in-35 year peak day and 1-in-10 year cold day design condition forecasts for core and firm noncore customers, respectively, through at least the 2020/21 operating season, assuming all transmission assets are in service. However, connected load in San Diego still far exceeds both these forecast figures and existing SDG&E system capacity, and SDG&E may need to curtail interruptible service as necessary to maintain firm service obligations. Moreover, if a substantial percentage of SDG&E noncore customers currently receiving interruptible service would seek to switch to firm service, SDG&E will probably not have enough firm capacity to meet all such requests.

Please take note that this assessment regarding the capability to serve core and firm noncore customers is an evaluation of the available pipeline capacity in San Diego only. Curtailments of firm noncore service are certainly possible, and in fact have recently happened, as a result of lack of supply delivered to the SDG&E system. Accordingly, SoCalGas and SDG&E no longer believe that the open season process is adequate in and of itself to signal the need to expand the SDG&E system capacity, and will soon propose a project that will include the enhancement of the reliability of service in San Diego.

II. CURRENT SDG&E SYSTEM CAPACITY

Given the current physical location of customers on the San Diego system, SDG&E has the capacity to serve 630 million cubic feet per day (MMcfd) of customer demand in the

[1] Titled "Opinion on Adequacy of Southern California Gas Company's and San Diego Gas and Electric Company's Gas Transmission Systems to Serve the Present and Future Needs of Core and Noncore Gas Customers."

winter operating season and 590 MMcfd of customer demand in the summer operating season. If core demand in the Rainbow Corridor continues to grow at its current pace, without system improvements or other enhancements, SDG&E system capacity may decline by the 2020/21 operating year to 600 MMcfd in the winter and 580 MMcfd in the summer.

III. CAPACITY OPEN SEASONS

In D.02-11-073, the Commission ordered SDG&E to conduct open seasons for the allocation of firm transportation capacity on its gas transmission system. In D.06-09-039, the Commission authorized SDG&E and Southern California Gas Company (SoCalGas) to conduct capacity open seasons in any areas of their local transmission systems that are constrained or are expected to be constrained. Pursuant to these orders, in May 2013 SDG&E conducted a capacity open season for the terms June 1, 2013, through May 31, 2015 (smaller customers) and June 1, 2013, through May 31, 2018 (larger customers).

D.06-09-039 further authorized SDG&E and SoCalGas to require longer-term commitments in the open seasons for large customers. Pursuant to this authorization, SDG&E and SoCalGas defined their open season terms for large customers as the earlier of (1) two years from the date that any associated facilities necessary for capacity improvements are placed into service; or (2) five years from the customer's sign-up date. The open seasons also provided that if the results do not require prorationing of capacity and the Commission agrees that no facilities are needed, large noncore customer commitments will have a term of two years. No prorationing of capacity was required for either 2013 open season, and in August 2013 the Commission approved our open season advice filing[2] which explained that, based on the open season results, no facility improvements were needed and requested approval to reduce the term to two years for large noncore customers.

IV. DEMAND FORECAST AND CAPACITY ASSESSMENT

In D.02-11-073, the Commission affirmed a 1-in-35 year cold day condition as the design criteria for core service, and established a new 1-in-10 year cold day design criteria for noncore firm service. These standards were reaffirmed in D.06-09-039. Table 1 shows SDG&E's long-term demand forecast for the 1-in-35 year and 1-in-10 year cold day demand conditions.

[2] SDG&E Advice Letter 2044-G.

Table 1
SDG&E Long-Term Demand Forecast

	1-in-35 Year Cold Day Demand (MMCFD)				1-in-10 Year Cold Day Demand [a/] (MMCFD)			
Operating Year [b/]	Core	Noncore C&I	EG	Total	Core	Noncore C&I	EG	Total/Firm
2014/15	394	0	0	394	366	65	102	533
2015/16	392	0	0	392	362	66	150	578
2016/17	392	0	0	392	361	67	163	591
2017/18	391	0	0	391	360	68	140	568
2018/19	390	0	0	390	359	68	169	596
2019/20	389	0	0	389	359	69	174	602
2020/21	389	0	0	389	358	70	167	595
2021/22	388	0	0	388	357	71	175	603
2022/23	389	0	0	389	358	71	172	601
2023/24	391	0	0	391	360	72	250	682
2024/25	392	0	0	392	361	73	203	637
2025/26	394	0	0	394	363	74	203	640
2030/31	403	0	0	403	371	78	203	651
2035/36	412	0	0	412	379	83	203	665

a/ Open season results for firm service shown for the 2013/14 and 2014/15 operating years. For the remaining term of the forecast, the gas demand forecasts for noncore commercial & industrial (C&I) and electric generation (EG) customer classes do not distinguish between firm and interruptible noncore service. Thus, for the purposes of this assessment, SDG&E assumed that all future peak C&I and EG loads elected firm noncore service.
b/ April through December, along with the following January through March.

Assuming the Rainbow Corriodor demand continues to grow at its current pace, the SDG&E winter system capacity would fall to 600 MMcfd by the 2020/21 operating season. As shown in Table 1, this is sufficient capacity to meet both the 1-in-35 year peak day and 1-in-10 year cold day design standards through at least the 2020/21 operating season. Additonal capacity may be necessary in San Diego after the 2020/21 operating year based on the forecast demand in Table 1.

This forecast of core and noncore demand is derived from data developed for the 2013 TCAP Settlement filing, and accounts for the retirement of the San Onofre Nuclear Generating Station (SONGS) and some new generation that has been proposed in San Diego County. However, until plans for replacing the loss of SONGS are further defined, SDG&E cannot forecast with any certainty what the impact will be on their gas transmission systems from that loss. Should there be a significant increase in local EG demand in San Diego to offset the loss of SONGS beyond that assumed in this forecast, it is probable that SDG&E would have insufficient capacity to serve that demand without curtailment. Accordingly, there is a growing need to construct new gas transmission capacity in the SDG&E service territory more quickly than Table 1 would indicate.

As noted above and in our prior semi-annual capacity planning reports, even though SDG&E has capacity to serve forecasted core and *firm* noncore 1-in-10 year cold day demand, connected load in San Diego still far exceeds these forecast figures and the existing SDG&E system capacity (currently 1.3 billion cubic feet per day of demand under a 1-in-10 year cold day conditon for the core with connected load for the noncore). This is because there is substantial interruptible noncore load on the SDG&E system, particularly EG load. Accordingly, it is entirely possible that total *firm* and *interruptible* noncore demand in San Diego may exceed the system capacity on a day warmer than the 1-in-10 year cold day, and SDG&E may need to curtail interruptible service as necessary to maintain firm service obligations. While this situation is exacerbated by the SONGS outage and the increasing generation in the San Diego region, it is not new; SDG&E has never represented that it was sufficent capacity to serve all interruptible demand in San Diego without curtailment.

Additionally, as SoCalGas and SDG&E continue to implement their pipeline safety programs, it may be necessary to temporarily reduce the operating pressure in our pipelines (as is the case right now with the southern portion of Line 1600). While SoCalGas and SDG&E will continue our practice of minimizing any resulting impact to our customers, it may be necessary to curtail some noncore customers (interrruptible and firm) or in order to maintain system integrity.

V. STATUS OF REQUESTS FOR FIRM SERVICE

SDG&E was able to satisfy all firm service requests during its last open season. However, firm service requests came within 57 MMcfd of exceeding available firm capacity in the winter operating season. As reported in AL 4512-G:

> Available capacity on the Rainbow Corridor and the SDG&E system is dependent upon the location of the customer demand on both systems. Based on the level of core demand in the Rainbow Corridor and on the SDG&E system, the current capacity of the SDG&E/Rainbow Corridor system is 740 MMcfd in the winter operating season and 680 MMcfd in the summer. This capacity was made available to both SoCalGas Rainbow Corridor customers and SDG&E customers during the Open Season. The firm service awards result in peak firm demand (core and noncore) of 682 MMcfd in the winter (548 MMcfd on the SDG&E system, 134 MMcfd in the Rainbow Corridor) and 521 MMcfd in the summer (339 MMcfd on the SDG&E system, 82 MMcfd in the Rainbow Corridor), resulting in excess capacity in both operating seasons.[3]

SoCalGas and SDG&E do not foresee being able to offer more firm capacity during the next open season than 740 MMcfd in the winter operating season and 680 MMcfd in the summer offered previously.

[3] AL 4512-G, page 2.

Since the October 2013 report, one additional noncore customer has signed an interruptible service contract for 127 thousand cubic feet per day (MCFD), and may seek firm service in SDG&E's next open season.

VI. POTENTIAL CAPACITY IMPROVEMENTS

In D.11-06-017, SoCalGas and SDG&E were ordered to pressure test or replace those pipelines that lack sufficient documentation of pressure testing to meet the requirements set forth in the Decision. In compliance with that order, SoCalGas and SDG&E have proposed to replace those lines that cannot be taken out of service for the pressure testing with minimal customer impacts. Once the new pipeline is installed, the original pipeline may be abandoned or tested and remain in service. For SDG&E, due to system reliability and customer impacts, a new line is specified to be placed in service prior to the testing of the 16-inch diameter Line 1600.

This plan to build a new pipeline to enable the testing of Line 1600 for safety reasons presents an opportunity for SDG&E to resolve long-standing reliability and capacity issues in San Diego as well. The 30-inch diameter Line 3010 transports 90% of SDG&E's gas supply. An outage on this pipeline, either planned or unplanned, would be very disruptive. An outage will severly reduce the SDG&E system capacity leading to noncore curtailments (both interruptible and firm), as well as jeopardize our ability to maintain continous, reliable service to core customers.

Using a 36-inch diameter for the new pipeline will provide the redundancy that is critically needed on the SDG&E system. Additionally, the 36-inch diameter pipeline will also provide new capacity on the San Diego system that we believe is needed, despite the results of the recent capacity open season and our long-term demand forecast. Nearly all of the interruptible demand in San Diego is associated with EG customers, who have been reluctant to bid for firm capacity, presumably because of the associated demand charges required by the open season process and the uncertainy of when they may be dispatched by the California Independent System Operator (CAISO). In the past, a curtailment of interruptible gas service did not have the potential to impact the electric grid stability since the EG plants were able to switch to fuel oil. For air quality reasons, this is no longer permitted, and both SoCalGas and SDG&E (gas operations) have increasingly been placed in the position of worrying about the reliability of both the gas network and the electric grid. SoCalGas and SDG&E cannot continue indefinitely to provide de-facto firm service to interruptible customers because the electric grid cannot sustain the impact of lost generation. To do so puts gas utilities in the position of weighing a grid collapse against core residential gas outages.

Certainly, increased communication between gas operations and CAISO can help mitigate this conflict, and SoCalGas, SDG&E, and CAISO have already undertaken steps to do just that. However, when the level of potential EG demand is as large as it is in San Diego, this can only go so far.

For these reasons, SoCalGas and SDG&E have recommended, and it would be prudent to construct, a 36-inch diameter pipeline prior to the testing of Line 1600. We have preliminarily estimated the cost of this pipeline to be $325 million,[4] with an estimated seven years to plan, construct, and place the new line into service. A 36-inch diameter pipeline will increase the SDG&E system capacity by 300 MMcfd, providing sufficient capacity to serve a significant level of EG demand under all temperature conditions. Just as significantly, a 36-inch diameter pipeline will be able to sustain at least the current 630 MMcfd of system capacity should SDG&E experience an outage on Line 3010.

SoCalGas and SDG&E will soon file an application in support of this 36-inch pipeline in which we provide in more detail our justification, costs, and alternatives.

[4] Direct capital costs only. *See* A.11-11-002, Testimony of Southern California Gas Company and San Diego Gas & Electric Company In Support of Proposed Natural Gas Pipeline Safety Enhancement Plan, Appendix IX-1-C, pages WP-IX-1-C1 and WP IX-1-C2.

Joff Morales
Regulatory Affairs
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 858-650-4098
JMorales@semprautilities.com

October 22, 2014

PUG 100
I.00-11-002

Mr. Edward Randolph
Director – Energy Division
California Public Utilities Commission
505 Van Ness Avenue, 4-A
San Francisco, CA 94102

Re: Gas Capacity Planning and Demand Forecast Semi-Annual Report

Dear Mr. Randolph,

Pursuant to California Public Utilities Commission Decision 02-11-073 in the Gas Transmission OII (I.00-11-002), SDG&E hereby submits the attached semi-annual report on its gas system capacity planning and demand forecasts.

If you have any questions, please contact Joff Morales at (858) 650-4098.

Sincerely,

Joff Morales
Regulatory Affairs

Enclosures

cc: Greg Reisinger, Energy Division

SAN DIEGO GAS & ELECTRIC COMPANY
GAS CAPACITY PLANNING AND DEMAND FORECAST
SEMI-ANNUAL REPORT

Pursuant to Ordering Paragraph 9 of California Public Utilities Commission (CPUC or Commission) Decision No. ("D.") 02-11-073[1] (issued November 21, 2002 in I.00-11-002), San Diego Gas & Electric Company (SDG&E) hereby submits its semi-annual report on its gas system capacity planning and demand forecasts.

This report addresses the adequacy of the SDG&E gas transmission system to meet the forecast of incremental gas demand, and whether that growth in gas demand would cause SDG&E the need to add incremental gas transmission capacity, within the confines of the process adopted by the Commission in D.02-11-073, i.e. using the firm service requests obtained during regular capacity open seasons, along with traditional demand forecasts, to signal whether additional capacity is needed.

I. EXECUTIVE SUMMARY

SDG&E system capacity continues to meet the 1-in-35 year peak day and 1-in-10 year cold day design condition forecasts for core and firm noncore customers, respectively, through at least the 2017/18 operating season, assuming all transmission assets are in service. However, connected load in San Diego still far exceeds both these forecast figures and existing SDG&E system capacity, and SDG&E may need to curtail interruptible service as necessary to maintain firm service obligations. Moreover, if a substantial percentage of SDG&E noncore customers currently receiving interruptible service would seek to switch to firm service, SDG&E will probably not have enough firm capacity to meet all such requests.

Please take note that this assessment regarding the capability to serve core and firm noncore customers is an evaluation of the available pipeline capacity in San Diego only. Curtailments of firm noncore service are certainly possible, and in fact have recently happened, as a result of lack of supply delivered to the SDG&E system. Accordingly, SoCalGas and SDG&E no longer believe that the open season process is adequate in and of itself to signal the need to expand the SDG&E system capacity, and are considering proposing a project that will include the enhancement of the reliability of service in San Diego.

II. CURRENT SDG&E SYSTEM CAPACITY

Given the current physical location of customers on the San Diego system, SDG&E has the capacity to serve 630 million cubic feet per day (MMcfd) of customer demand in the winter operating season and 590 MMcfd of customer demand in the summer operating season. If core demand in the Rainbow Corridor continues to grow at its current pace,

[1] Titled "Opinion on Adequacy of Southern California Gas Company's and San Diego Gas and Electric Company's Gas Transmission Systems to Serve the Present and Future Needs of Core and Noncore Gas Customers."

without system improvements or other enhancements, SDG&E system capacity may decline by the 2020/21 operating year to 600 MMcfd in the winter and 580 MMcfd in the summer.

III. CAPACITY OPEN SEASONS

In D.02-11-073, the Commission ordered SDG&E to conduct open seasons for the allocation of firm transportation capacity on its gas transmission system. In D.06-09-039, the Commission authorized SDG&E and Southern California Gas Company (SoCalGas) to conduct capacity open seasons in any areas of their local transmission systems that are constrained or are expected to be constrained. Pursuant to these orders, in May 2013 SDG&E conducted a capacity open season for the terms June 1, 2013, through May 31, 2015 (smaller customers) and June 1, 2013, through May 31, 2018 (larger customers).

D.06-09-039 further authorized SDG&E and SoCalGas to require longer-term commitments in the open seasons for large customers. Pursuant to this authorization, SDG&E and SoCalGas defined their open season terms for large customers as the earlier of (1) two years from the date that any associated facilities necessary for capacity improvements are placed into service; or (2) five years from the customer's sign-up date. The open seasons also provided that if the results do not require prorationing of capacity and the Commission agrees that no facilities are needed, large noncore customer commitments will have a term of two years. No prorationing of capacity was required for either 2013 open season, and in August 2013 the Commission approved our open season advice filing[2] which explained that, based on the open season results, no facility improvements were needed and requested approval to reduce the term to two years for large noncore customers.

IV. DEMAND FORECAST AND CAPACITY ASSESSMENT

In D.02-11-073, the Commission affirmed a 1-in-35 year cold day condition as the design criteria for core service, and established a new 1-in-10 year cold day design criteria for noncore firm service. These standards were reaffirmed in D.06-09-039. Table 1 shows SDG&E's long-term demand forecast for the 1-in-35 year and 1-in-10 year cold day demand conditions.

[2] SDG&E Advice Letter 2044-G.

Table 1
SDG&E Long-Term Demand Forecast

	1-in-35 Year Cold Day Demand (MMCFD)				1-in-10 Year Cold Day Demand [a/] (MMCFD)			
Operating Year [b/]	Core	Noncore C&I	EG	Total	Core	Noncore C&I	EG	Total/Firm
2014/15	390	0	0	390	368	65	102	535
2015/16	389	0	0	389	367	59	156	582
2016/17	391	0	0	391	369	60	175	604
2017/18	391	0	0	391	369	60	170	599
2018/19	393	0	0	393	370	61	186	617
2019/20	394	0	0	394	372	61	194	627
2020/21	394	0	0	394	372	61	207	640
2021/22	395	0	0	395	372	61	180	613
2022/23	396	0	0	396	374	61	190	625
2023/24	397	0	0	397	375	61	187	623
2024/25	398	0	0	398	376	61	182	619
2025/26	400	0	0	400	378	60	180	618
2030/31	410	0	0	410	387	59	180	626
2035/36	421	0	0	421	397	59	180	636

a/ Open season results for firm service shown for the 2014/15 operating year. For the remaining term of the forecast, the gas demand forecasts for noncore commercial & industrial (C&I) and electric generation (EG) customer classes do not distinguish between firm and interruptible noncore service. Thus, for the purposes of this assessment, SDG&E assumed that all future peak C&I and EG loads elected firm noncore service.

b/ April through December, along with the following January through March.

Assuming the Rainbow Corriodor demand continues to grow at its current pace, the SDG&E winter system capacity would fall from its current level of 630 MMcfd to 600 MMcfd by the 2020/21 operating season. As shown in Table 1, this is sufficient capacity to meet the 1-in-35 year peak day design standard through the forecast period. SDG&E winter system capcity would fall below the 1-in-10 year cold day design standard after the 2017/18 operating season, assuming a linear interpolation of the system capacity between its 2014/15 and 2020/21 levels. Additional capacity may be necessary in San Diego after the 2017/18 operating year based on the forecast demand in Table 1.

This forecast of core and noncore demand is derived from data developed for the 2014 California Gas Report,[3] and accounts for the retirement of the San Onofre Nuclear Generating Station (SONGS) and some new generation that has been proposed in San Diego County. However, until plans for replacing the loss of SONGS are further defined, SDG&E cannot forecast with any certainty what the impact will be on their gas

[3] The California Gas Report (CGR) EG demand forecast was adjusted per D.02-11-073 for this table. D.02-11-073 requires the assumption of a cold year condition, rather than the normal condition used for the CGR. All other CGR assumptions, such as those for energy efficiency and renewable sources, were applied to the EG demand forecast presented in Table 1.

transmission systems from that loss. Should there be a significant increase in local EG demand in San Diego to offset the loss of SONGS beyond that assumed in this forecast, it is probable that SDG&E would have insufficient capacity to serve that demand without curtailment. Accordingly, there is a growing need to construct new gas transmission capacity in the SDG&E service territory more quickly than Table 1 would indicate.

As noted above and in our prior semi-annual capacity planning reports, even though SDG&E has capacity to serve forecasted core and *firm* noncore 1-in-10 year cold day demand, connected load in San Diego still far exceeds these forecast figures and the existing SDG&E system capacity (currently 1.3 billion cubic feet per day of demand under a 1-in-10 year cold day conditon for the core with connected load for the noncore). This is because there is substantial interruptible noncore load on the SDG&E system, particularly EG load. Accordingly, it is entirely possible that total *firm* and *interruptible* noncore demand in San Diego may exceed the system capacity on a day warmer than the 1-in-10 year cold day, and SDG&E may need to curtail interruptible service as necessary to maintain firm service obligations. While this situation is exacerbated by the SONGS outage and the increasing generation in the San Diego region, it is not new; SDG&E has never represented that it was sufficent capacity to serve all interruptible demand in San Diego without curtailment.

Additionally, as SoCalGas and SDG&E continue to implement their pipeline safety programs, it may be necessary to temporarily reduce the operating pressure in our pipelines (as is the case right now with the southern portion of Line 1600). Furthermore, due to permitting and other construction issues necessary to repair the pipeline, the pipeline's operating pressure may be reduced for an extended period of time. While SoCalGas and SDG&E will continue our practice of minimizing any resulting impact to our customers, it may be necessary to curtail some noncore customers (interrruptible and firm) or in order to maintain system integrity.

V. STATUS OF REQUESTS FOR FIRM SERVICE

SDG&E was able to satisfy all firm service requests during its last open season. However, firm service requests came within 57 MMcfd of exceeding available firm capacity in the winter operating season. As reported in AL 4512-G:

> Available capacity on the Rainbow Corridor and the SDG&E system is dependent upon the location of the customer demand on both systems. Based on the level of core demand in the Rainbow Corridor and on the SDG&E system, the current capacity of the SDG&E/Rainbow Corridor system is 740 MMcfd in the winter operating season and 680 MMcfd in the summer. This capacity was made available to both SoCalGas Rainbow Corridor customers and SDG&E customers during the Open Season. The firm service awards result in peak firm demand (core and noncore) of 682 MMcfd in the winter (548 MMcfd on the SDG&E system, 134 MMcfd in the Rainbow Corridor) and 521 MMcfd in the summer (339

MMcfd on the SDG&E system, 82 MMcfd in the Rainbow Corridor), resulting in excess capacity in both operating seasons.[4]

SoCalGas and SDG&E do not foresee being able to offer more firm capacity during the next open season than 740 MMcfd in the winter operating season and 680 MMcfd in the summer offered previously.

Since the April 2014 report, one existing noncore customer signed two interruptible service contracts totaling 222 thousand cubic feet per day (MCFD), and may seek firm service in SDG&E's next open season.

VI. POTENTIAL CAPACITY IMPROVEMENTS

In D.11-06-017, SoCalGas and SDG&E were ordered to pressure test or replace those pipelines that lack sufficient documentation of pressure testing to meet the requirements set forth in the Decision. In compliance with that order, SoCalGas and SDG&E have proposed to replace lines that cannot be taken out of service for the pressure testing with minimal customer impacts. One such line is SDG&E's 16-inch diameter Line 1600, which transports roughly 10% of SDG&E's gas supply.

The initial Pipeline Safety Enhancement Plan (PSEP) submitted by SoCalGas and SDG&E proposed the construction of a new pipeline to enable the hydrotesting of Line 1600. Pursuant to D.14-06-007, the Commission's decision regarding SoCalGas and SDG&E's PSEP, this proposed new pipeline would be the subject of a separate CPUC application.

SoCalGas and SDG&E believe that the need to pressure test or replace Line 1600 could provide an opportunity for SDG&E to resolve long-standing reliability and capacity issues in San Diego. The 30-inch diameter Line 3010 transports 90% of SDG&E's gas supply. An outage on this pipeline, either planned or unplanned, would be very disruptive. An outage will severely reduce the SDG&E system capacity leading to noncore curtailments (both interruptible and firm), as well as jeopardize our ability to maintain continous, reliable service to core customers. Construction of a new 36-inch diameter pipeline would provide needed redundancy in the event of a planned or unplanned outage on Line 3010. A new 36-inch diameter pipeline would also provide additional capacity that could be beneficial for SDG&E customers and the electric grid in the event of future capacity shortages. Despite the results of the recent capacity open season, SDG&E ran out capacity last winter, and needed to curtail service on an emergency basis to electric generators on February 6, 2014. We are concerned that this will not be an isolated occurrence.

[4] AL 4512-G, page 2.

Joff Morales
Regulatory Affairs
9305 Century Park Court
San Diego, CA 92123

Tel: 858-650-4098
JMorales@semprautilities.com

April 30, 2015

PUG 100
I.00-11-002

Mr. Edward Randolph
Director – Energy Division
California Public Utilities Commission
505 Van Ness Avenue, 4-A
San Francisco, CA 94102

Re: Gas Capacity Planning and Demand Forecast Semi-Annual Report

Dear Mr. Randolph,

Pursuant to California Public Utilities Commission Decision 02-11-073 in the Gas Transmission OII (I.00-11-002), SDG&E hereby submits the attached semi-annual report on its gas system capacity planning and demand forecasts.

If you have any questions, please contact Joff Morales at (858) 650-4098.

Sincerely,

Joff Morales
Regulatory Affairs

Enclosures

cc: Greg Reisinger, Energy Division

SAN DIEGO GAS & ELECTRIC COMPANY
GAS CAPACITY PLANNING AND DEMAND FORECAST
SEMI-ANNUAL REPORT

Pursuant to Ordering Paragraph 9 of California Public Utilities Commission (CPUC or Commission) Decision No. ("D.") 02-11-073[1] (issued November 21, 2002 in I.00-11-002), San Diego Gas & Electric Company (SDG&E) hereby submits its semi-annual report on its gas system capacity planning and demand forecasts.

This report addresses the adequacy of the SDG&E gas transmission system to meet the forecast of incremental gas demand, and whether that growth in gas demand would cause SDG&E the need to add incremental gas transmission capacity, within the confines of the process adopted by the Commission in D.02-11-073, i.e. using the firm service requests obtained during regular capacity open seasons, along with traditional demand forecasts, to signal whether additional capacity is needed.

I. EXECUTIVE SUMMARY

SDG&E system capacity continues to meet the 1-in-35 year peak day and 1-in-10 year cold day design condition forecasts for core and firm noncore customers, respectively, through at least the 2017/18 operating season, assuming all transmission assets are in service. However, connected load in San Diego still far exceeds both these forecast figures and existing SDG&E system capacity, and SDG&E may need to curtail interruptible service as necessary to maintain firm service obligations. Moreover, if a substantial percentage of SDG&E noncore customers currently receiving interruptible service would seek to switch to firm service, SDG&E will probably not have enough firm capacity to meet all such requests.

Please take note that this assessment regarding the capability to serve core and firm noncore customers is an evaluation of the available pipeline capacity in San Diego only. Curtailments of firm noncore service are certainly possible, and in fact have recently happened, as a result of lack of supply delivered to the SDG&E system. Accordingly, SoCalGas and SDG&E no longer believe that the open season process is adequate in and of itself to signal the need to expand the SDG&E system capacity, and are considering proposing a project that will include the enhancement of the reliability of service in San Diego.

II. CURRENT SDG&E SYSTEM CAPACITY

Given the current physical location of customers on the San Diego system, SDG&E has the capacity to serve 630 million cubic feet per day (MMcfd) of customer demand in the winter operating season and 590 MMcfd of customer demand in the summer operating season. If core demand in the Rainbow Corridor continues to grow at its current pace,

[1] Titled "Opinion on Adequacy of Southern California Gas Company's and San Diego Gas and Electric Company's Gas Transmission Systems to Serve the Present and Future Needs of Core and Noncore Gas Customers."

without system improvements or other enhancements, SDG&E system capacity may decline by the 2020/21 operating year to 600 MMcfd in the winter and 580 MMcfd in the summer.

III. CAPACITY OPEN SEASONS

In D.02-11-073, the Commission ordered SDG&E to conduct open seasons for the allocation of firm transportation capacity on its gas transmission system. In D.06-09-039, the Commission authorized SDG&E and Southern California Gas Company (SoCalGas) to conduct capacity open seasons in any areas of their local transmission systems that are constrained or are expected to be constrained. Pursuant to these orders, in May 2013 SDG&E conducted a capacity open season for the terms June 1, 2013, through May 31, 2015 (smaller customers) and June 1, 2013, through May 31, 2018 (larger customers).

D.06-09-039 further authorized SDG&E and SoCalGas to require longer-term commitments in the open seasons for large customers. Pursuant to this authorization, SDG&E and SoCalGas defined their open season terms for large customers as the earlier of (1) two years from the date that any associated facilities necessary for capacity improvements are placed into service; or (2) five years from the customer's sign-up date. The open seasons also provided that if the results do not require prorationing of capacity and the Commission agrees that no facilities are needed, large noncore customer commitments will have a term of two years. No prorationing of capacity was required for either 2013 open season, and in August 2013 the Commission approved our open season advice filing[2] which explained that, based on the open season results, no facility improvements were needed and requested approval to reduce the term to two years for large noncore customers.

IV. DEMAND FORECAST AND CAPACITY ASSESSMENT

In D.02-11-073, the Commission affirmed a 1-in-35 year cold day condition as the design criteria for core service, and established a new 1-in-10 year cold day design criteria for noncore firm service. These standards were reaffirmed in D.06-09-039. Table 1 shows SDG&E's long-term demand forecast for the 1-in-35 year and 1-in-10 year cold day demand conditions.

[2] SDG&E Advice Letter 2044-G.

Table 1
SDG&E Long-Term Demand Forecast

	1-in-35 Year Cold Day Demand (MMCFD)				1-in-10 Year Cold Day Demand [a/] (MMCFD)			
Operating Year [b/]	Core	Noncore C&I	EG	Total	Core	Noncore C&I	EG	Total
2015/16	389	0	0	389	367	59	156	582
2016/17	391	0	0	391	369	60	175	604
2017/18	391	0	0	391	369	60	170	599
2018/19	393	0	0	393	370	61	186	617
2019/20	394	0	0	394	372	61	194	627
2020/21	394	0	0	394	372	61	207	640
2021/22	395	0	0	395	372	61	180	613
2022/23	396	0	0	396	374	61	190	625
2023/24	397	0	0	397	375	61	187	623
2024/25	398	0	0	398	376	61	182	619
2025/26	400	0	0	400	378	60	180	618
2030/31	410	0	0	410	387	59	180	626
2035/36	421	0	0	421	397	59	180	636

a/ The gas demand forecasts for noncore commercial & industrial (C&I) and electric generation (EG) customer classes do not distinguish between firm and interruptible noncore service. Thus, for the purposes of this assessment, SDG&E assumed that all future peak C&I and EG loads elected firm noncore service.

b/ April through December, along with the following January through March.

Assuming the Rainbow Corriodor demand continues to grow at its current pace, the SDG&E winter system capacity would fall from its current level of 630 MMcfd to 600 MMcfd by the 2020/21 operating season. As shown in Table 1, this is sufficient capacity to meet the 1-in-35 year peak day design standard through the forecast period. SDG&E winter system capcity would fall below the 1-in-10 year cold day design standard after the 2017/18 operating season, assuming a linear interpolation of the system capacity between its 2014/15 and 2020/21 levels. Additional capacity may be necessary in San Diego after the 2017/18 operating year based on the forecast demand in Table 1.

This forecast of core and noncore demand is derived from data developed for the 2014 California Gas Report,[3] and accounts for the retirement of the San Onofre Nuclear Generating Station (SONGS) and some new generation that has been proposed in San Diego County. However, until plans for replacing the loss of SONGS are further defined, SDG&E cannot forecast with any certainty what the impact will be on their gas transmission systems from that loss. Should there be a significant increase in local EG demand in San Diego to offset the loss of SONGS beyond that assumed in this

[3] The California Gas Report (CGR) EG demand forecast was adjusted per D.02-11-073 for this table. D.02-11-073 requires the assumption of a cold year condition, rather than the normal condition used for the CGR. All other CGR assumptions, such as those for energy efficiency and renewable sources, were applied to the EG demand forecast presented in Table 1.

forecast, it is probable that SDG&E would have insufficient capacity to serve that demand without curtailment. Accordingly, there is a growing need to construct new gas transmission capacity in the SDG&E service territory more quickly than Table 1 would indicate.

As noted above and in our prior semi-annual capacity planning reports, even though SDG&E has capacity to serve forecasted core and *firm* noncore 1-in-10 year cold day demand, connected load in San Diego still far exceeds these forecast figures and the existing SDG&E system capacity (currently 1.3 billion cubic feet per day of demand under a 1-in-10 year cold day conditon for the core with connected load for the noncore). This is because there is substantial interruptible noncore load on the SDG&E system, particularly EG load. Accordingly, it is entirely possible that total *firm* and *interruptible* noncore demand in San Diego may exceed the system capacity on a day warmer than the 1-in-10 year cold day, and SDG&E may need to curtail interruptible service as necessary to maintain firm service obligations. While this situation is exacerbated by the SONGS outage and the increasing generation in the San Diego region, it is not new; SDG&E has never represented that it was sufficent capacity to serve all interruptible demand in San Diego without curtailment.

Additionally, as SoCalGas and SDG&E continue to implement their pipeline safety programs, it may be necessary to temporarily reduce the operating pressure in our pipelines (as is the case right now with the southern portion of Line 1600). Furthermore, due to permitting and other construction issues necessary to repair the pipeline, the pipeline's operating pressure may be reduced for an extended period of time. While SoCalGas and SDG&E will continue our practice of minimizing any resulting impact to our customers, it may be necessary to curtail some noncore customers (interrruptible and firm) or in order to maintain system integrity.

V. STATUS OF REQUESTS FOR FIRM SERVICE

SDG&E was able to satisfy all firm service requests during its last open season. However, firm service requests came within 57 MMcfd of exceeding available firm capacity in the winter operating season. As reported in AL 4512-G:

> Available capacity on the Rainbow Corridor and the SDG&E system is dependent upon the location of the customer demand on both systems. Based on the level of core demand in the Rainbow Corridor and on the SDG&E system, the current capacity of the SDG&E/Rainbow Corridor system is 740 MMcfd in the winter operating season and 680 MMcfd in the summer. This capacity was made available to both SoCalGas Rainbow Corridor customers and SDG&E customers during the Open Season. The firm service awards result in peak firm demand (core and noncore) of 682 MMcfd in the winter (548 MMcfd on the SDG&E system, 134 MMcfd in the Rainbow Corridor) and 521 MMcfd in the summer (339 MMcfd on the SDG&E system, 82 MMcfd in the Rainbow Corridor), resulting in excess capacity in both operating seasons.[4]

[4] AL 4512-G, page 2.

SoCalGas and SDG&E do not foresee being able to offer more firm capacity during the next open season than 740 MMcfd in the winter operating season and 680 MMcfd in the summer offered previously.

Since the October 2014 report, one customer signed four interruptible noncore service contracts at four different locations totallying 128 thousand cubic feet per day (MCFD), and may seek firm service during the 2015 SDG&E Pipeline Capacity Open Season currently in progress

Results of the current open season will be reflected in the October 2015 report.

VI. POTENTIAL CAPACITY IMPROVEMENTS

In D.11-06-017, SoCalGas and SDG&E were ordered to pressure test or replace those pipelines that lack sufficient documentation of pressure testing to meet the requirements set forth in the Decision. In compliance with that order, SoCalGas and SDG&E have proposed to replace lines that cannot be taken out of service for the pressure testing with minimal customer impacts. One such line is SDG&E's 16-inch diameter Line 1600, which transports roughly 10% of SDG&E's gas supply.

The initial Pipeline Safety Enhancement Plan (PSEP) submitted by SoCalGas and SDG&E proposed the construction of a new pipeline to enable the hydrotesting of Line 1600. Pursuant to D.14-06-007, the Commission's decision regarding SoCalGas and SDG&E's PSEP, this proposed new pipeline would be the subject of a separate CPUC application.

SoCalGas and SDG&E believe that the need to pressure test or replace Line 1600 could provide an opportunity for SDG&E to resolve long-standing reliability and capacity issues in San Diego. The 30-inch diameter Line 3010 transports 90% of SDG&E's gas supply. An outage on this pipeline, either planned or unplanned, would be very disruptive. An outage will severely reduce the SDG&E system capacity leading to noncore curtailments (both interruptible and firm), as well as jeopardize our ability to maintain continous, reliable service to core customers. Construction of a new 36-inch diameter pipeline would provide needed redundancy in the event of a planned or unplanned outage on Line 3010. A new 36-inch diameter pipeline would also provide additional capacity that could be beneficial for SDG&E customers and the electric grid in the event of future capacity shortages. Despite the results of the recent capacity open season, SDG&E ran out capacity last winter, and needed to curtail service on an emergency basis to electric generators on February 6, 2014. We are concerned that this will not be an isolated occurrence.