APPENDIX G
SCE REPORT TO CAISO

G-1—Update to SCE's April 7th Report to the CAISO (March 17, 2005)
G-2—Cost Effectiveness Report (April 7, 2004)

Update to SCE's April 7th Report to the CAISO entitled "Devers-Palo Verde No. 2 Cost-Effectiveness Report"

March 17, 2005

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Update Summary

SCE based its April 7th, 2004 "Devers-Palo Verde No. 2 Cost-Effectiveness Report" (Original Report) on assumptions found in SCE's 2003 Long Term Procurement Plan (LTPP). SCE has since filed its 2004 LTPP with the California Public Utilities Commission (CPUC)[1] and has updated its economic analysis of DPV2 using 2004 LTPP assumptions. This update communicates the results of this updated economic analysis which have changed since the Original Report due to the new assumptions[2].

Most of the April 7th, 2004 "Devers-Palo Verde No. 2 Cost-Effectiveness Report" (Original Report) contains current information; SCE's methodology and description of analyzing the economics of new transmission projects for example. Those results that have changed however are shown below as updates to sections in the Original Report. For example, if results have changed in section II D of the Original Report, the change will be found in section II D of this update. If this update does not show a section found in the Original Report, then the information contained in that section is still current.

III Methodology

D 2. a) Benefits Due to Cost Savings (Change in Total Production Costs):

Benefits due to cost savings have been revised as follows: SCE updated load, natural gas prices, and available hydro generation assumptions, extended the number of production simulations from 2009 to 2014 from 2009 to 2012, and updated present value calculations

[1] Rulemaking (R.) 04-04-003. SCE's LTPP can be found at http://www3.sce.com/law/cpucproceedings.nsf/vwUFiling?SearchView&Query=long+term+procurement+plan&Start=1&Count=30. Specifically, the analysis performed to evaluate DPV2's economics ties directly to SCE's Medium Load Scenario.

[2] Typical updates to a LTPP include revised forecasts for loads, natural gas prices, and available hydro generation.

from a 2004 NPV to a 2005 NPV. The Figures below updates Figure 3 and Figure 4 found in the Original Report.

Figure 3 – Change in Total Production Costs for CAISO Ratepayers

CAISO Ratepayers (Real $2004 in millions)

	2009	2010	2011	2012	2013	2014
Consumer Surplus	$81	$158	$166	$161	$208	$193
URG Producer Surplus	($28)	($58)	($61)	($61)	($79)	($71)
Transmission Congestion Revenue	($8)	($13)	($13)	($11)	($11)	($11)
Net Benefits	$45	$87	$92	$89	$118	$111

Figure 4 – Net Present Value of Change in Total Production Costs for CAISO Ratepayers:

CAISO Ratepayers (2005 NPV, $ millions)

	2005 NPV* for Life of Project
Consumer Surplus	$1,850
URG Producer Surplus	($685)
Transmission Congestion Revenue	($96)
Net Benefits	$1,069

(* Discount rate of 10.5%)

D 2. b) Benefits Due to New Transmission Capacity:

SCE's Original Report listed one year of transmission capacity benefits. As shown in the Capacity Benefit formula in the Original Report, these benefits were dependent upon load forecasts in the southwest. Load in Arizona and southwest Nevada is now expected to be higher than originally forecasted. The increased loads have resulted in reducing transmission capacity benefits to zero.

D 2. c) Benefits Due to Increased Transmission Revenues:

Wheeling service and Existing Transmission Contracts' (ETCs) estimated benefits are revised to be approximately $0.6 million annually of increased revenue to SCE from certain ETCs and approximately $2.4 million annually of increased CAISO wheeling revenues to SCE or about $30 million (2005 NPV) over the life of the project.

D 2. d) Negative Benefits Due to Increased Transmission Losses:

The CAISO and SCE separately calculated benefits due to transmission losses but with opposite results; the CAISO found losses decrease, SCE estimated losses increase with the addition of DPV2. The CAISO utilized a production model that included individual transmission line data, whereas SCE's production model aggregates transmission data. This distinction in transmission modeling may be the cause of SCE's and the CAISO's dissimilar results. SCE believes its estimate of transmission losses using a production simulation is inconclusive. Since results are inconclusive, SCE removed the transmission loss component from its economic analysis.

D 2. e) Conclusion of DPV2's Cost-Effectiveness:

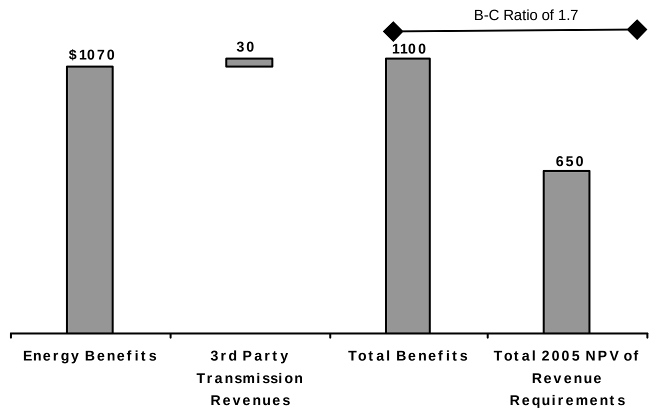
Figure 5 illustrates the updated economic benefits of DPV2 is about $1.1 billion, comprised of energy savings, and third-party transmission revenues. The 2005 present value costs for DPV2 is estimated at $650 million. With a benefit-to-cost ratio of about 1:7:1, DPV2 is a highly cost-effective project for customers in the CAISO area.[3]

[3] Those benefits are those accruing to ratepayers whose utilities are CAISO Participating Transmission Owners that placed their transmission facilities under the operational control of the CAISO.

Figure 5 – Cost-Effectiveness Summary of DPV2

DPV2 Projected Lifecycle Benefits

(2005 NPV, $ Millions, 10.5 % discount rate per annum)



VIII Appendix E – CAISO Requested Information

A. <u>WECC Total Production Costs</u>

Figure 12 is revised from the Original Report to the new figure shown below.

Figure 12 – WECC Wide Production Costs (Real, 2004 $M)

WECC Production Costs (Real $2004 in millions)

	2009	2010	2011	2012	2013	2014
Without DPVII	11,332	19,086	19,945	20,548	21,198	21,644
With DPVII	11,322	19,065	19,924	20,527	21,172	21,619
Net Benefits	11	21	21	21	26	25

B. Impact to Arizona

Figure 13 is revised from the Original Report to the new figure shown below.

Figure 13 – Arizona Producer and Ratepayer Benefits (Real, 2004 $M)

Arizona Benefits (Real $2004 in millions)

	2009	2010	2011	2012	2013	2014
Consumer Surplus	($25)	($37)	($39)	($40)	($45)	($45)
URG Producer Surplus	$18	$27	$29	$29	$31	$30
Transmission Congestion Revenue	($1)	($2)	($2)	($2)	($2)	($2)
Net Benefits	($7)	($11)	($11)	($12)	($16)	($17)

Devers-Palo Verde No. 2

Cost-Effectiveness Report

SOUTHERN CALIFORNIA
EDISON®
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April 7, 2004

Devers-Palo Verde No. 2 Cost-Effectiveness Report

Cost Effectiveness Summary

Southern California SCE (SCE) analyzed the cost-effectiveness of constructing a new 500 kV transmission line between California and Arizona (Devers-Palo Verde No. 2 or DPV2). SCE's cost-effectiveness analysis compares California ratepayers' benefits due to increasing California import capability from the Palo Verde area to the costs of the project. The main benefits are that greater access to surplus economic out-of-state generation reduces energy costs to customers throughout California. SCE calculated the benefits accruing to ratepayers in the California Independent System Operator's (CAISO) control area[1].

SCE's evaluation of DPV2 concludes that, DPV2 is cost-effective with a benefit-to-cost ratio of almost 3:1. This analysis utilized a reasonable set of assumptions, and accounted for the uncertainty of major economic drivers. This analysis included the uncertainty of natural gas prices, load forecasts, and available hydro generation. SCE modeled major transmission operational constraints into California using realistic operational limits. In addition, the analysis attempted to quantify all reasonable and realistic costs and benefits to CAISO ratepayers. For example, costs of west of Devers substation, voltage support devices, and increased losses due to DPV2 were all captured. To be thorough, SCE also estimated the benefits of increased transmission revenues and a transmission capacity value.

SCE's sensitivity analyses showed that the project's expected cost-effectiveness could range from a benefit-cost-ratio of 1.5:1 to about 3:1; depending upon assumptions of future benefits and whether transmission lines are rated at operational or thermal limits. SCE derived the 3:1 benefit-cost-ratio from 2004 net present value of benefits of about $1,700 million, and a cost estimate of $590 million. These results assume benefits beyond 2013 are held at zero real inflation. If future annual benefits were held to 2012 levels for the life of the project, the overall 2004 net present value of benefits decline to $1,300 million, and the benefit-to-cost ratio decrease to about 2:1. These are the results if transmission ratings are held at their operational limits. SCE believes that operational limits are more realistic than using thermal limits. If transmission ratings were raised to their thermal limits, DPV2's benefits would be around $870[2] million and the benefit-to-cost ratio about 1.5:1.

The majority of benefits arise from the increased ability to import lower cost energy located in the Palo Verde area of Arizona into California. SCE's analysis indicates an excess of about 6,500 MW of cost-effective surplus generation is available in the Palo Verde and Nevada area starting in 2008. The Southwest Transmission Expansion Planning (STEP)[3] working group independently concluded a similar

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[1] Those benefits accruing to ratepayers whose transmission facilities are under the operational control of the CAISO.

[2] Assuming future benefits are held to zero real inflation from 2012.

[3] The Southwest Transmission Expansion Plan (STEP) is a sub-regional planning group that was formed to address transmission concerns in the Arizona, southern Nevada, southern California, and northern Mexico area. Due to a large amount of new generation developed in this area, it was apparent to many that the transmission grid would be inadequate

magnitude of generation should be available to import into California. SCE evaluated the benefits of this excess generation from 2009 to 2012. The evaluation started in 2009 because that is the year DPV2 is proposed to be operational.

SCE assumed that the benefits of accessing Palo Verde generation in the southwest area will continue beyond 2012. This assumption is based on a belief that new generation in Arizona will continue to have economic advantages over new projects in California. These advantages include access to lower cost natural gas, less restrictive permitting, lower taxes, and lower labor rates. As long as these advantages exist, it is reasonable to expect that a continuing benefit will accrue from new generation sources in the Palo Verde area. Therefore, it is reasonable to assume that Californians will continue to benefit from new generation beyond those plants that are in construction and permitted.

After considering all costs and benefits and uncertainty of major economic drivers, SCE believes that DPV2 is a cost effective project for CAISO ratepayers with a benefit-to-cost ratio of around 3:1. SCE respectfully requests that the CAISO find DPV2 to be a necessary and cost-effective addition to the CAISO Controlled Grid and fully support SCE in its future applications involving DPV2. It is SCE's intention to pursue additional permitting activities at the California Public Utilities Commission once we receive unambiguous approval from the CAISO.

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to efficiently deliver that power to the major load areas. The goal of STEP is "To provide a forum where all interested parties are encouraged to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, Nevada, Mexico, and southern California areas that is capable of supporting a competitive efficient and seamless west-side wholesale electricity market while meeting established reliability standards". (See, Jan. 17th pdf file at: http://www1.caCAISO.com/docs/2002/11/04/2002110417450022131.html)

I. Introduction

As provided in Section 3 of the CAISO Tariff, SCE submits this report for the CAISO's use in evaluating the cost-effectiveness of constructing the Devers-Palo Verde No. 2 – 500 kV transmission line. DPV2 is an economic project under Section 3.2.1.1 of the CAISO Tariff. SCE believes this report provides sufficient information for the CAISO to find DPV2 necessary and cost-effective. SCE respectfully requests that the CAISO find DPV2 to be a necessary and cost-effective addition to the CAISO Controlled Grid and support SCE in its application for a Certificate of Public Necessity and Convenience (CPCN) expected to be filed with the California Public Utilities Commission (CPUC or Commission) in 2004. It is SCE's intention to pursue additional permitting activities at the California Public Utilities Commission once we receive unambiguous approval from the CAISO.

II. CAISO's Key Principles of an Economic Methodology

During a March 16, 2004 Transmission Economic Analysis Methodology (TEAM) workshop, the CAISO presented five key principles[4] of a proposed generic methodology to evaluate economic transmission projects. The CAISO is required by the California Public Utilities Commission (CPUC) to recommend a methodology to evaluate economic transmission projects[5]. SCE submits the following information in subsections A, B, C, D, and E to explain how SCE's analysis comports with each of the proposed key principles.

A. <u>Benefits Framework</u>

The CAISO described its Benefits Framework principle as a "*standard framework to measure benefits regionally and separately from consumers, producers, and transmission owners from different regions*".

Section III(D) of this report explains that SCE's benefits framework consists of the <u>same</u> three primary metrics identified in the CAISO's Benefits framework; namely consumer surplus, producer surplus, and transmission congestion revenues. Along with these primary benefits, SCE

[4] Presentation entitled "Transmission Economic Assessment Methodology, Introduction, Purpose, and Progress". Second Stakeholder Workshop – March 16, 2004. This report is available on the CAISO website at the following address: http://www1.caCAISO.com/docs/2003/03/18/2003031815303519270.html

[5] As part of the AB 970 Phase 5 proceeding (I.00-11-001).

also includes what it categorizes as secondary benefits consisting of transmission capacity, transmission revenues, and losses. Using this framework DPV2 was shown to have a benefit-to-cost ratio around 3:1 for CAISO ratepayers using the same methodology the CAISO proposes. In Section VIII of this report, SCE also describes DPV2's impacts over the WECC and Arizona regions.

B. Market Prices

The CAISO described its Market Prices principle as one that will "*utilize market prices to evaluate transmission expansion*". SCE utilized market prices to evaluate DPV2 as explained in Sections III(D)(2) and IV(A) of this report.

In summary, market prices were developed using a production simulation tool specifically designed to forecast market prices, then applied to CAISO formulas to calculate consumer surplus, producer surplus, and transmission congestion revenues for CAISO ratepayers. The derivation of consumer surplus utilized the market prices forecasted in the CAISO area with and without installing DPV2. This market price differential was multiplied by CAISO load to determine consumer surplus. SCE's producer surplus calculations also utilized market prices to forecast the revenues of utility retained generation. Market prices were also utilized to estimate transmission congestion revenues as the flow across transmission paths multiplied by the market price differential between where energy was generated to where energy was consumed by load. Finally, market prices were utilized to estimate the energy costs of losses incurred in delivering energy to consumers.

C. Uncertainty

The CAISO describes its Uncertainty principle as one to "*consider through a wide range of future system conditions; dry-hydro, gas prices, demand growth, under and over entry of generation*".

SCE's analysis captured a significant range of uncertainty by performing random Monte Carlo (i.e., stochastic) simulations for various factors which include hydro variation, gas prices, and demand growth uncertainty, described in detail in Section IV. This stochastic analysis provides a wide range of future system conditions through use of volatility and correlation parameters which were patterned using historical data. For example in Section IV, Figure 9 shows that gas price volatilities range from about \$2 to \$6 (\$/mmBtu).

SCE's estimate of under and over entry of generation is essentially captured by Monte Carlo simulation of demand growth and forced outages. Section IV, Figure 8 illustrates load growth ranges from about 18 to 20 (GWh). Under a low load growth scenario generation would be in excess of need and in a high load growth scenario generation supply would be short.

D. Network Representation

The CAISO describes its Network Representation principle as one that will "*demonstrate flow is physically feasible*".

In Section IV(C), SCE describes transmission flows are constrained at their operational limits. SCE represented the network in two different ways. In its economic analysis, SCE used operational limits to constrain flows between geographic areas. Specifically, SCE's network representation in its economic analysis incorporated Southern California Import Transmission limits in order to capture real operational constraints to assure that flow is physically feasible. SCE also performed significant power flow analysis to demonstrate the physical feasibility of the project. Appendix A of DVP2's Technical report provides single line diagrams with the magnitude of power flows when DPV2 is modeled in and out of operation.

E. Alternatives (Generation/Demand Side Substitution)

The CAISO describes its Generation/Demand Side Substitution principle as to "*evaluate alternatives to transmission expansion*".

Section III(A) describes in detail five alternatives SCE evaluated to arrive at the conclusion that DPV2 is the best project to meet the project scope of accessing expected levels of generation supplies in the Arizona/Nevada areas. Section III(A)(2) describes how alternatives such as generation and demand side substitutions are best evaluated with respect to this project.

III. Methodology

SCE analyzed the economics of DPV2 by first determining its overall objective. SCE's objective is to access surplus energy located in the southwest (Arizona) or the south (Mexico) and to provide the transmission infrastructure necessary to enable a more liquid and competitive electricity market. Since a number of projects can meet this import objective, a methodology was developed to determine the most favorable project. SCE's method has the following four major elements:

- Project Screening
- Project Ordering
- Establishing a Baseline
- Project Evaluation

This approach started with a list of competing projects, which were then screened to determine the most viable. Viable projects were then chronologically ordered in terms of their expected operating dates for use in production simulations. Using the results of the production simulations, the economics of competing projects were compared using a net-present value basis to formulate which project best met the import objective. After conducting this analysis, SCE concluded constructing DPV2 is cost-effective for California ratepayers. Details of this approach follow.

A. Project Screening

SCE evaluated several potential projects which could increase transmission import capability into California either from the southwest or the south. Using this project scope, SCE developed a list of new projects and upgrades to existing facilities which would meet the import objective. This list was developed using personal knowledge and projects identified via the STEP process as references. The following projects were identified as potentially meeting the import objective.

Alternative	Import Objective
1. Second Devers-Palo Verde 500 kV transmission line (DPV2)	Increase imports from the Palo Verde area by increasing the Path 49[6] transfer capability
2. Second Southwest Power Link 500 kV transmission line (SWPL)	Increase imports from the Palo Verde area by increasing the Path 49 transfer capability
3. Upgrade SWPL No. 1, Devers-Palo Verde No. 1, Navajo-Crystal, and Moenkopi-Eldorado series capacitors (Path 49 Series Capacitor Upgrades, or Series Cap)[7]	Increase imports from the Palo Verde area by increasing the Path 49 transfer capability
4. New Imperial Valley-Devers 500 kV transmission line (IV-Devers)	Increase imports from Mexico area by increasing the Path 45[8] transfer capability
5. Combination of constructing a new Imperial Valley-Devers 500 kV transmission line and upgrading SWPL No. 1, Devers-Palo Verde No. 1, Navajo-Crystal, and Moenkopi-Eldorado series capacitors (IV-Devers & Series)	Increase imports from the Palo Verde and Mexico areas by increasing both the Path 49 and Path 45 transfer capabilities

[6] Path 49 transfer capacity as defined in the 2003 WECC Path Rating Catalogue.

[7] This project was screened with an initial additional rating or transfer capability of 760 MW. Since this screening, the transfer capability has been revised to 505 MW. Since SCE estimates this project is still cost effective, conclusions stated in this report about this project remain valid. SCE is evaluating this project separately from this report using a 505 MW rating. Outside of this screening analysis, DPV2 is evaluated using the 505 MW rating.

[8] Path 45 transfer capacity as defined in the 2003 WECC Path Rating Catalogue.

Each of these projects was screened using a rough estimate of project costs and benefits. SCE conducted this screening in 2003, so a 2003 NPV of costs (Costs) of each project were developed. Costs were estimated for major cost components. No special cost studies[9] were conducted since this step of our methodology is a project screening analysis. Benefits of each project were developed by estimating each project's change to Total Production Costs using deterministic production simulations (See Appendix A for an explanation of the production simulation used in analyzing DPV2) and then calculating the 2003 NPV of such benefits (Benefits). Projects having positive net benefits were further analyzed in a later stage of analysis.

Deterministic analysis is appropriate for screening, but is not sufficient by itself for final cost-effectiveness evaluations. Deterministic analyses have only a single set of input forecasts and by themselves do not fully take into account many uncertainties related to electricity markets. By contrast, SCE used stochastic (Monte Carlo) analysis for its cost-effectiveness evaluation of DPV2 in the final project evaluation step so as to incorporate the uncertainty of key critical assumptions (i.e. load, natural gas prices, hydro production, and random generation unit forced outages).

Deterministic production cost benefits were calculated from June 1, 2008[10] up to December 31, 2012 for each alternative[11]. The economics of each project was then compared using their benefit-to-cost ratios and net benefits over 46 year expected project lives. The results of this economic screening are shown on the following Figures 1 and 2.

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[9] Major cost components were identified. Special cost studies such as walking proposed sites to identify other cost components will be conducted for those projects passing the screening test.

[10] 2008 was chosen since it was thought DPV2 would have an operating date of 2008 at the time of this screening.

[11] For these deterministic screenings, maximum transmission line ratings were utilized. Stochastic analysis used operational transmission line ratings as a further analytical refinement.

Figure 1 – Benefit-Cost Comparison of Alternative Projects

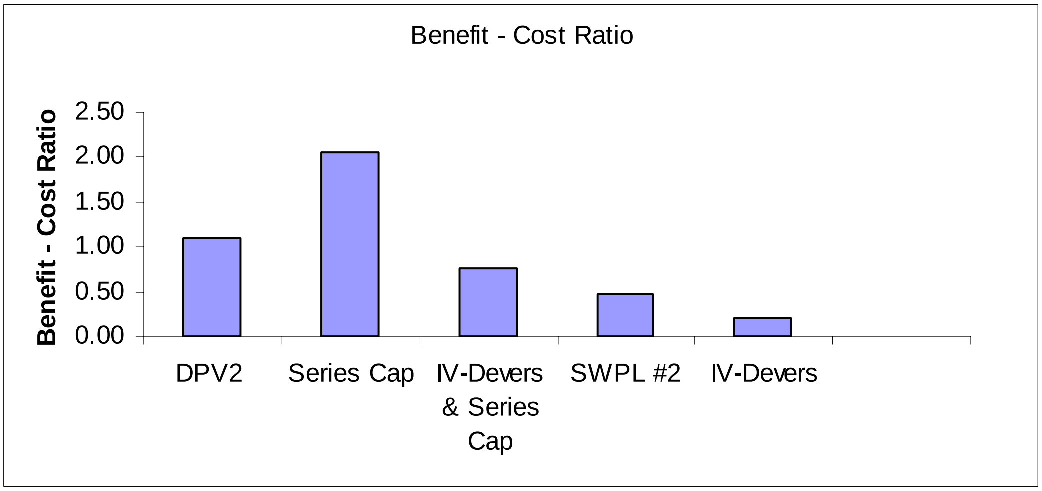
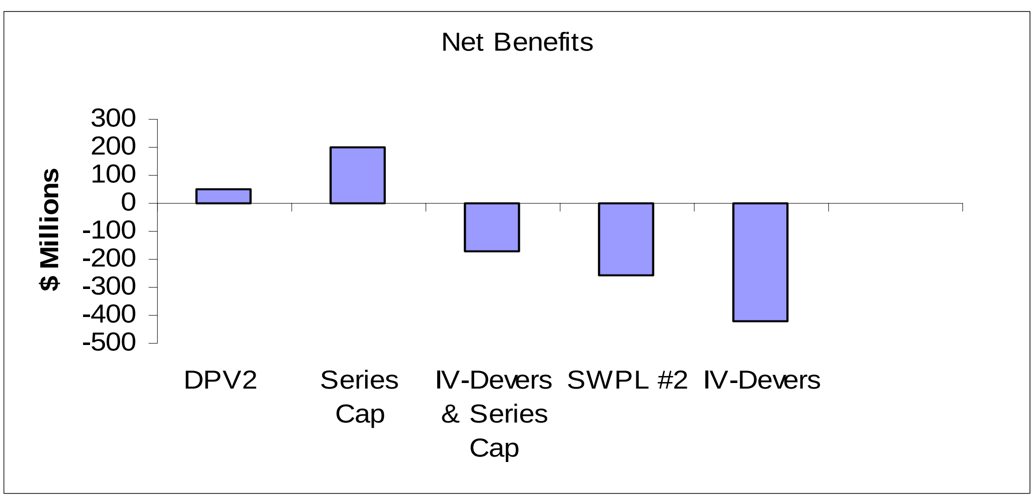


Figure 2 – Net Benefits Comparison of Alternative Projects



1. Results of Economic Screening

As shown in the Figures above, Devers-Palo Verde No. 2 and the Path 49 Series capacitor upgrade projects show sufficient benefits to evaluate further; both projects having positive net benefits. The rationales for further studying these projects, and excluding the remaining projects, are described in more detail below.

a) Devers-Palo Verde No. 2 – 500 kV Transmission Line Alternative

DPV2 will increase import capability over Path 49 by 1200 MW. This import capability yielded a deterministic benefit-to-cost ratio of slightly over 1:1, indicating a need for a more comprehensive cost and benefit analysis.

DPV2's Costs include not only costs of the line, but in addition include costs of upgrade facilities West of SCE's Devers substation totaling over $100 million, and about $75 million dollars in voltage support facilities. For screening purposes, DPV2's costs were estimated to be about $490[12] million. Benefits were estimated to be over $540 million, producing a benefit cost ratio over 1:1.

b) Imperial Valley-Devers 500 kV Transmission Line Alternative

Costs of a new 1,400 MW Imperial Valley-Devers 500 kV line were compared to the Benefits of increasing imports from the south and southwest. The Costs of constructing Imperial Valley-Devers are estimated to be about $530 million using a typical planning estimate by accounting for major transmission line, substation, land components, and west of Devers upgrades and voltage support facilities as estimated for DPV2.

The estimated $110 million of Benefits due to accessing surplus power in Mexico are low compared to their estimated Costs. Excess generation located in Mexico had an impact of lowering energy production costs in California, but not as significant as resources in the Palo Verde area. As a result, the project's 2003 NPV benefit-to-cost ratio is 0.2, which is far less cost-effective than DPV2. Consequently, this alternative was excluded from further consideration.

[12] Since this screening, DPV2's cost estimate has increased to $590 million due to changes in project scope. Benefits have also increased to over $1,700 million due to accounting for uncertainty of load, natural gas prices, hydro generation, and operational transmission constraints.

c) Southwest Power Link No. 2 Transmission Line Alternative

A second Southwest Power Link (SWPL 2)[13] 500 kV line was evaluated as an alternative because it would increase imports from the Palo Verde area similar to DPV2. Our screening indicates SWPL 2 has an uneconomic benefit-to-cost ratio of about 0.5. Costs of constructing SWPL 2 were not estimated in detail. Instead, costs of constructing DPV2 were used as a proxy ($490 million). Such a proxy is reasonable since the line lengths and other major cost components are comparable. In fact, constructing SWPL No. 2 would likely cost more than DPV2 since SWPL No. 2 would require significant purchases of land while DPV2 does not, and is about 20% longer. Any increase in costs would further lower the project's benefits-to-cost ratio. Benefits were estimated to be about half of those from DPV2 ($230 million). This is due to congestion in transmission facilities north of the San Diego area.

Using these assumptions, SWPL 2 has a 2003 NPV of benefits-to-cost ratio of about 0.5, and therefore this project is not considered a viable import alternative.

d) Path 49 Series Capacitor Upgrades Alternative

Upgrading the SWPL No. 1, Devers-Palo Verde No. 1, Navajo-Crystal, and Moenkopi-Eldorado series capacitors and their associated facilities is roughly estimated to Cost about $190 million. The Costs of constructing these upgrades were estimated using a typical planning estimate by calculating major transmission line, and substation components.

The deterministic production cost Benefits is estimated to be $390 million, yielding a benefit-to-cost ratio over 2:1. Since the project has a large benefit-to-cost ratio, and seems to have broad support in the STEP arena, SCE added this project to its base case (Section II(B) below provides additional discussion).

e) Combination of Path 49 Series Capacitor Upgrades and Imperial Valley-Devers 500 kV Transmission Line Alternative

As shown in section (b) above, the Imperial Valley-Devers 500 kV Transmission Line was not cost-effective as a stand-alone project. SCE questioned whether this new line in combination with the Path 49 series capacitor upgrades would deliver Benefits in excess of their individual project benefits. The incremental Benefit of the combined project is about $50 million greater than the sum of the individual projects Benefits ($500 million). The Costs of the combined projects are estimated to be about $720 million. The

[13] SWPL 1 is defined as the 500 kV line connecting the Palo Verde-North Gila-Imperial Valley-Miguel substations. SWPL 2 is one alternative to increase imports into California. SWPL 2 would be constructed as a parallel line to SWPL 1.

combined costs far exceed the combined benefits yielding a benefit-to-cost ratio of 0.7 ($550/$720). This alternative was not evaluated further.

2. Investing in New Generation, New Renewable Resources, or New Demand Side Management Programs

a) Generation Alternatives

As described the Preferred Resource Plan SCE filed with the Commission on April 15th, 2003, SCE is not in a position to make significant long-term commitments in generation, whether these commitments are utility generation or through purchase power contract. Two necessary preconditions must take place before SCE can make such commitments:

- Stabilizing SCE's customer base and clarifying SCE's long-term load responsibilities by establishing fair rules for future Direct Access, exit fees for municipalization and other departing load, and equal resource adequacy requirements for all Load Serving Entities;
- Continuing the efforts that the Commission and SCE have undertaken together since September 2001 to restore the regulated utility's creditworthiness and financial viability, including: (1) establishing a durable, secure and commercially realistic cost recovery framework to enable new regulated utility investments in generation; (2) recognizing all the costs associated with power contracting including significant collateral requirements and off-balance-sheet debt equivalence of long-term contracts – whether California Department of Water Resources (DWR), Qualifying Facilities (QF) or bilateral; and (3) clarifying that the DWR contracts will never be assigned to SCE.

DPV2 will help to mitigate the risks associated with SCE's uncertain regulatory environment by providing access to additional surplus generation. Access to a larger pool of potential resources may allow SCE to sign shorter term contracts with existing suppliers. Shorter term contracts can be reasonably relied upon to meet customers' needs in the face of significant uncertainty and are a lower risk approach until policy issues regarding customer base are resolved. The use of shorter term contracts will also reduce the negative credit rating impacts associated with power contract debt equivalence[14].

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[14] The two major credit rating agencies, Standard and Poor's Rating Agency and Moody's Investor Service both treat long-term power contracts as liabilities and impute a portion of the value of these contracts as debt on utility balance sheets. Shorter-term contracts, especially those with terms of three years or less, are deemed to have little or no debt equivalence.

b) Renewables Alternatives

SCE's evaluation of DPV 2 includes full compliance with California's Renewable Portfolio Standard (RPS), which requires each load serving entity to increase its commitments to renewable power 1 percent per year such that 20 percent of retail sales are met with renewable power by 2017. SCE is the leader in renewable power procurement in California and currently has a plan to meet RPS requirements ahead of schedule. SCE views the DPV2 project as one that works with the RPS requirements as it allows for greater renewables to be developed elsewhere for import into California. Therefore, rather than viewing renewables as an alternative, SCE suggests that the DPV2 project be viewed as a facilitator of additional renewable power for CAISO customers.

c) Demand Side Alternatives

SCE's current resource plan includes a significant increase in cost-effective energy efficiency and demand response investment over and above the levels funded in rates and through Public Goods Charge (PGC) funds. Current PGC funding levels are about $90 million per year and SCE received authority to invest an additional $60 million per year for energy efficiency. This is a substantial investment in energy efficiency and it is unclear how much potential cost-effective energy efficiency will be available in the 2009 timeframe. Nevertheless, SCE will continue to pursue cost-effective energy efficiency in 2009 and beyond, regardless of whether the DPV2 project is constructed in operation. It would be unwise to forego a cost-effective transmission project such as DPV2 in the hopes of pursuing unknown demand-side alternatives far in the future. Therefore, SCE finds DPV2 to be a cost-effective project even when demand-side resources are considered.

3. Summary of Transmission Alternatives

SCE evaluated a reasonable set of transmission alternatives for meeting the objective of increasing import capability into California. DPV2 increases import capability by 1200 MW with favorable economics. The screening results indicate no other alternatives examined were viable substitutes for DPV2. The Path 49 Series Capacitor Upgrades were the only other cost-effective transmission project, but this project can be pursued in addition to DPV2. SCE believes the Series Capacitor Upgrades are sufficiently cost-effective to include them in its evaluation of DPV2. No additional analysis was performed on the other alternatives.

B. Project Ordering

SCE based its economic analysis on its 2003 Preferred Resource Plan, which incorporated substantial commitments to energy efficiency, demand response, and renewable power among other attributes. Transmission projects are added to this base scenario using their operating dates. A DPV2 operating date of June 1, 2009 is expected to leave sufficient time to complete licensing, construction, and regulatory approvals.

In addition, it appears the Path 49 Series Capacitor Upgrades project will likely be operational prior to DPV2 for four reasons. First, the analysis being conducted by STEP coincides with SCE's analysis that the project is cost-effective[15]. Second, it is likely the Path 49 Series Capacitor Upgrades will be completed prior to DPV2 since there are potential project sponsors. Third, the Path 49 Series Capacitor Upgrades can be completed earlier than constructing a new line since they involve less construction and are not expected to require a CPCN[16]. Finally, DPV2 is even more cost-effective without the Path 49 upgrades; so if it can be shown that DPV2 is cost-effective with the Path 49 Series Capacitor Upgrades in place, then DPV2's benefits-to-costs ratio would be improved further still if the proposed upgrades are not completed prior to DPV2.

For these reasons, SCE decided it was reasonable to include the Path 49 Series Capacitor Upgrades in the base case prior to evaluating DPV2. SCE assumed an operating date of June 1, 2006 to reflect a likely completion schedule.

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[15] The STEP process has shown increasing the ratings of several series capacitors located on Path 49 lines has sufficient benefits and viability to include in its baseline (See, http://www1.caCAISO.com/docs/2002/11/04/2002110417450022131.html internet address). SCE's analysis confirms the STEP analysis. Upgrading the series capacitors and other related facilities on the SWPL No. 1, Devers-Palo Verde No. 1, Navajo-Crystal, and Moenkopi-Eldorado lines has sufficient benefits and likely sponsors to occur prior to DPV2's operating date. SCE added these projects to its baseline and incrementally evaluated DPV2's benefits above these added facilities.

[16] Upgrades to substation facilities do not normally require a CPCN (See, CPUC General Order No. 131-D).

C. Setting a Baseline

When evaluating new projects, it is important to have a comprehensive understanding of what generation and transmission will or won't be constructed in the future. SCE's base case was developed by adding cost-effective projects from the screening analysis above, and transmission and generation new entry and retirements known in the industry[17]. SCE utilized publicly available information relating to the likelihood of future transmission and generation projects and the following criteria.

Criteria used to add transmission

- New lines are added that affect the market model topology
- Construction should be fairly certain
- Ratings and WECC system impacts should be fairly certain
- Utility specific projects – such as DPV2

Criteria used to add generation

- Project is being constructed and has a reasonable likelihood of being completed (either substantially constructed, and have financing completed, or be an investor owned or municipality utility project.). SCE also added generation if public data reasonably supported such an addition.

Criteria used in generation retirements

- Specific published retirement dates,
- Reach a life of 55 years or,
- Retirements due to air quality restrictions
- Consistency with California Commission planning assumptions

A list of projected new entries and retirements may be found in the appendices of this report. Appendix B shows new transmission projects, Appendix C shows new generation projects and Appendix D shows generation retirements. This set of new entry and retirements together with the projects identified in our screening analysis defines SCE's base case.

[17] Information gathered from publications or reports from the CAISO, CEC, and WECC, among others.

D. Project Evaluation

Project screening indicated DPV2 to be a cost-effective project, but a more thorough analysis was performed to better understand the project's total costs and benefits. DPV2's project scope was analyzed in detail to identify all costs, including special cost studies to further narrow cost uncertainties. Project benefits were also analyzed in more detail by conducting stochastic production simulations in which the uncertain nature of future natural gas prices, load growth, and hydro generation were included to provide expected values for production costs over a wide range of uncertainties. Also, operational transmission limits[18] were used in our project evaluation. The following sections detail SCE's evaluation of DPV2.

1. CAISO Ratepayer Perspective

SCE's cost-effectiveness evaluation of DPV2 is a life-cycle benefit-to-cost analysis from a CAISO ratepayer perspective. A life-cycle perspective measures total benefits and costs over the entire period of the project's expected life (2009-2055). SCE used a net present value (NPV) analysis to bring all benefits and costs to the base year of 2004. Measuring benefits and costs from a CAISO ratepayer perspective means that SCE valued all benefits and costs using an estimate of the revenue requirements that CAISO ratepayers would incur either with or without the project.

The CAISO ratepayer perspective is the proper scope of review since when DPV2 is approved, its revenue requirements will be collected under the CAISO Transmission Access Charge (TAC) that is paid by the ratepayers of all CAISO Participating Transmission Owners[19]. Constructing DPV2 is also expected to benefit non-CAISO ratepayers because all California electricity customers can benefit from lower average energy market prices due to the construction of DPV2.

2. Benefit-Cost Analysis

Net Present Value (NPV) is the discounted monetized value of expected benefits or costs. Discounting benefits and costs transforms gains and losses occurring in different time periods to a common unit of measurement. The ratio of the NPV of benefits to the NPV of project revenue requirements[20] is the benefit-to-cost ratio. Benefit-to-cost ratios above 1.0 indicate

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[18] Seasonal Southern California Import Transmission nomogram limits were enforced.

[19] Some of the TAC is paid for by non-CAISO ratepayers who are wheeling energy through the CAISO control area and by entities with Existing Transmission Contracts with Participating Transmission Owners whose rates are tied to their transmission revenue requirement.

[20] A revenue requirement is calculated for two types of expenditures -- O&M and capital. Both types of expenditures are converted to revenue requirements using an annual methodology. O&M expenditures, direct and indirect, are converted to

projects which benefit ratepayers. The following equation sets forth the benefit-to-cost ratio used in this analysis:

$$\text{B/C Ratio} = \frac{\sum_{I=2009}^{2055} \text{Net Present Value of [Total Production Costs (Without DPV2 – With DPV2) + Additional Benefits]}}{\sum_{I=2009}^{2055} \text{(Net Present Value of DPV2 Revenue Requirement Costs)}}$$

Where:

- "Total Production Costs (Without DPV2 – With DPV2)" is an estimate of the benefit CAISO customers may obtain through access to low cost generation supplies, producers revenues and transmission congestion revenues; and
- "Additional Benefits" are benefits from transmission capacity, and transmission wheeling revenues, and negative benefits due to transmission losses (described below).
- "Net Present Value of DPV2 Revenue Requirement Costs" includes the recovery of capital and fixed operations and maintenance expense associated with the project.

The majority of DPV2's benefits are the result of increased access to surplus economic out-of-state generation, which will lower energy market prices in California. Other benefits to California ratepayers include capacity benefits due to increased transmission capacity to other markets for capacity, and increased transmission revenues from wheeling charges and Existing Transmission Contracts. SCE estimates CAISO system losses increase with DPV2, and are incorporated into the project's cost-effectiveness as a negative benefit. These quantifiable benefits are described in more detail below.

Costs of DPV2 are provided in Section I(C) of the Technical report. The 2004 NPV of revenue requirement of DPV2's costs are estimated to be $590 million dollars.

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revenue requirements, by applying a franchise fee and uncollectibles factor. Capital expenditures, direct and indirect, are first accumulated over time, applying AFUDC (essentially interest during construction), to arrive at a total installed cost. The total installed cost is then converted to a revenue requirements stream over the useful life of the asset. The annual amount of this revenue requirements stream is a function of the book and tax lives, cost of capital, and tax rates.

a) <u>Benefits Due To Cost Savings (Change in Total Production Costs):</u>

The benefits due to lower energy prices are estimated by using production simulations[21] to calculate Total Production Costs over a three and a half year study period[22] and then extrapolating future benefits over the life of the project. SCE chose this study period as a reasonable balance between sufficient data to forecast future generation patterns and a study period short enough that it is practical to use production simulation. A longer simulation period was thought to derive little forecasting benefit as the uncertainty is so large beyond 2012 that the precision of such simulation would be small relative to this uncertainty.

The change in Total Production Costs, or energy cost savings, are defined as the benefits or costs to CAISO ratepayers due to three quantities: consumer surplus, producer surplus, and transmission congestion revenues when comparing benefits with and without DPV2. Consumer Surplus[23] is defined as the value of the energy to the CAISO ratepayer, minus the price paid for it. A beneficial transmission project will lower the energy costs to CAISO ratepayers.

Producer Surplus is defined as the difference between the energy price paid to the utility retained generation, and the variable operating cost to produce it. Total Production Costs include a value of producer surplus for utility retained generation only because utility retained generation reflects costs or benefits that accrue to ratepayers. Since a new transmission line could cause a utility owned generator to earn less than its costs, such ratepayer costs should be included in a ratepayer test.

Transmission Congestion Revenue[24] is the revenue customers receive due to congestion charges. Transmission Congestion Revenue was calculated for transmission facilities under the operational control of the CAISO.

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[21] Seasonal Southern California Import Transmission nomogram limits were enforced during these simulations.

[22] The production simulation study period started from DPV2's proposed operating date of June 1, 2009 and ended on December 31, 2012.

[23] Mathematically, consumer surplus equals the change in market prices with and without DPV2 times the CAISO area load.

[24] Transmission Congestion Revenue was calculated for all lines in or out of the CAISO control area using the following relationship for each transmission path: Transmission Congestion Revenue = hourly flow * (hourly market clearing price Zone B – hourly market clearing price Zone A), where Zone B is the market clearing price of the zone where energy is flowing from, and Zone A is the market clearing price of the zone where energy is flowing to (i.e. the differential in market clearing prices from both ends of a particular transmission path times the energy flow).

The summation of Consumer Surplus, Producer Surplus, and Transmission Congestion Revenue is thought to capture the major quantifiable ratepayer costs and benefits of a transmission project and be equal to its Total Production Costs. Total Production Costs for CAISO ratepayers are shown in the next Figure as net benefits.

Figure 3 – Change in Total Production Costs for CAISO Ratepayers

CAISO Ratepayers (Real $2003 in millions)

	2009	2010	2011	2012
Consumer Surplus	$160	$240	$230	$250
URG Producer Surplus	($30)	($50)	($50)	($50)
Transmission Congestion Revenue	($20)	($30)	($30)	($30)
Net Benefits	$110	$160	$150	$170

A project has positive benefits if Total Production Costs are less after it's constructed. For example, if Total Production Costs are calculated for the existing CAISO area, and then calculated again with the addition of a new project, such as DPV2, and if Total Production Costs decrease, then the additional project has positive benefits for CAISO ratepayers. For DPV2, benefits are explicitly calculated between 2009 and 2012. Benefits beyond 2012 are projected at the 2012 level at zero real growth for the remainder of the project's life (2013-2055). The net benefits for DPV2 is about $1.7 billion, as shown below.

Figure 4 – Net Present Value of Change in Total Production Costs for CAISO Ratepayers

CAISO Ratepayers (2004 NPV, $ millions)

	2004 NPV* for Life of Project
Consumer Surplus	$2,450
URG Producer Surplus	($470)
Transmission Congestion Revenue	($310)
Secondary Benefits (losses, T. cap, T. revenues)	$20
Net Benefits	$1,690

(* Discount rate of 10.5%)

b) Benefits Due To New Transmission Capacity

The benefits of DPV2 include the avoided cost of marginal generating capacity. Marginal generating capacity value is defined as a fraction of, up to 100%, the deferral value of a combustion turbine proxy[25] to the load serving entity. A new transmission project such as DPV2 can only provide a capacity benefit if the project enables access to a lower cost and available generation capacity market that would otherwise not be accessible. To illustrate, if the California generation capacity market values capacity at $100, but a new transmission line can enable access to a surplus, neighboring capacity market selling capacity for less, say at $80, then the transmission project provides a capacity benefit of the difference, or $20 to California.

A real capacity market, such as that operating in the New York and PJM markets today, does not exist for the California-Arizona area. However, SCE has established a reasonable method for estimating the value of capacity associated with DPV2 by identifying the surplus generation in the Arizona area that could be used to meet California capacity requirements and is transferable over the line. Essentially, the value of this capacity due to new transmission, 'T', is equal to SCE's estimate of its avoided cost of capacity, 'AC', multiplied by the result of 1 minus the ratio of the new transmission capacity rating to the quantity of excess generation, 'G', in the Arizona area. The value of capacity to 'T' cannot be lower than 0% and cannot exceed 100%.

Capacity Benefit =

$$\sum_{I=2009}^{2012} \text{Net Present Value of } [AC * T * (1 - T / G)]$$

[25] The costing methodology established in Commission Decision (D.) 82.12.120 directs PG&E, SCE and SDG&E to base their long-run cost of capacity according to a combustion turbine proxy.

Where:

- 'T' is defined as Path 49 operational rating increase due to DPV2.
- 'AC' is SCE's avoided cost estimate for marginal capacity and energy based on the CT deferral methodology. SCE currently estimates its future marginal capacity costs to be \$85.9/kW-yr in 2008 and \$89.8/kW-yr in 2009, or 100% the full value of a combustion turbine proxy in both years.
- 'G' is excess generation capacity in the Arizona area that exceeds the area's load and reserves requirements and its current export transfer capability. In the SCE database, this excess generation is expected to drop below DPV2's line rating by 2010.

SCE estimates constructing DPV2 provides access to approximately 6,500 MW of excess Arizona and Nevada generation that otherwise would not be available to California consumers. Much of this excess capacity can be tapped through existing lines and the Series Capacitor upgrade project, and even more is expected to meet local Arizona and Nevada needs as load grows in the area. These factors reduce the excess generation that can be attributable to DPV2 by its operating date. The \$20 million capacity benefit (2004 NPV) was positive only over a one year period because by the year 2010, SCE believes the amount of surplus generation will fall below DPV2's capacity, thus eliminating capacity benefits as described in the formula above.

c) <u>Benefits Due To Increased Transmission Revenues:</u>

DPV2 will increase the Transmission Revenue Requirements used to develop rates for both CAISO Wheeling service and Existing Transmission Contracts' (ETCs). This is estimated to result in approximately \$0.5 million annually of increased revenue to SCE[26] from certain ETCs and approximately \$1.8 million annually of increased CAISO wheeling revenue to SCE (totaling \$ 2.3 million) or about \$21 million (2004 NPV) over the life of the project. SCE's ETC revenues are reflected in its Other Operating Revenue which serves to reduce its overall transmission revenue requirement. Wheeling revenue received by SCE from the CAISO for wheeling through or out of the CAISO grid is reflected in SCE's transmission revenue balancing account.

The methodology for deriving the impact of DPV2 on SCE's Wheeling Revenue is based on the ratio of the Wheeling Access Charge with and without DPV2 and historical SCE Wheeling revenue information.

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[26] Benefits due to increased transmission revenues were estimated for SCE rather than all Participating Transmission Owners due to available data.

The methodology for deriving the impact of the ETCs' revenue is based on the ratio of the Transmission Revenue Requirements with and without DPV2 multiplied by the ETCs' revenues. The ETCs consist of transmission service contracts with Colton, and LADWP.

d) Negative Benefits Due To Increased Transmission Losses:

Annual CAISO transmission system losses[27] are estimated to increase annually by about 50 GWh due to DPV2, increasing costs due to the project by about $2 million per year ($23 million, 2004 NPV). Conceptually, this seems a reasonable result when considering how far generation in the Arizona/Nevada area is from the California load being served. Some generation in California with a close proximity to California load will be displaced by the more distant, but less costly generation from Palo Verde. Losses generally increase as the distance between generation supply and load centers increases.

Increased annual system losses were estimated by comparing stochastic production simulation runs with and without DPV2. The model is populated with loss factors derived from OASIS bulletin boards, such as the CAISO Transmission Meter Multipliers. Increased losses due to serving CAISO load were summed over a year to derive annual losses, which were then multiplied by the differential[28] in Market Clearing Prices to determine the annual costs of losses[29]. A cost stream was developed by assuming a zero real escalation from 2013[30] for the remainder of project's life. The 2004 net present value of this stream was then deducted from the project's benefits.

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[27] For this analysis, losses mean real power losses and not reactive power losses.

[28] This differential refers to the decrease in estimated Market Clearing Prices (MCP) for CAISO ratepayers due to construction of DPV2; calculated as (MCP before DPV2 – MCP after DPV2).

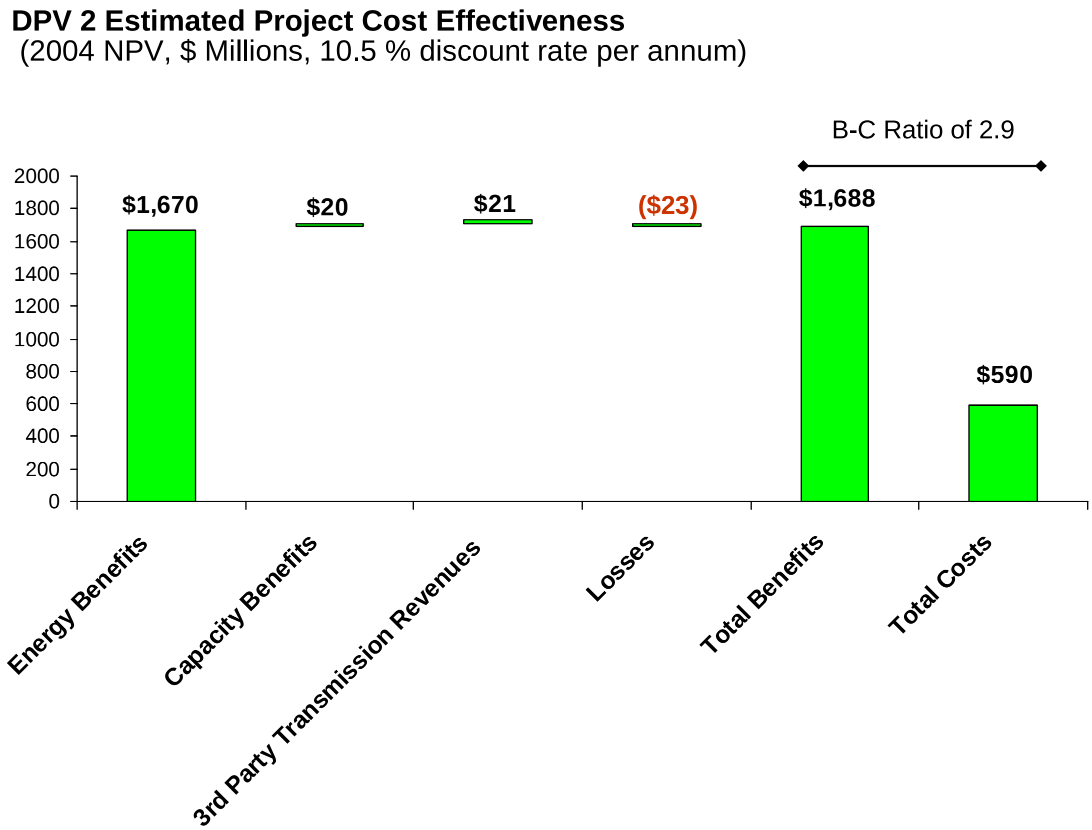
[29] Stochastic analysis results are computed one week out of the month, and every fourth hour to reduce computation time.

[30] Approximately a 3% rate of inflation.

e) <u>Conclusion of DPV2's Cost Effectiveness:</u>

A summary of DPV's cost-effectiveness combining all costs and benefits is shown below.

Figure 5 – Cost-Effectiveness Summary of DPV2



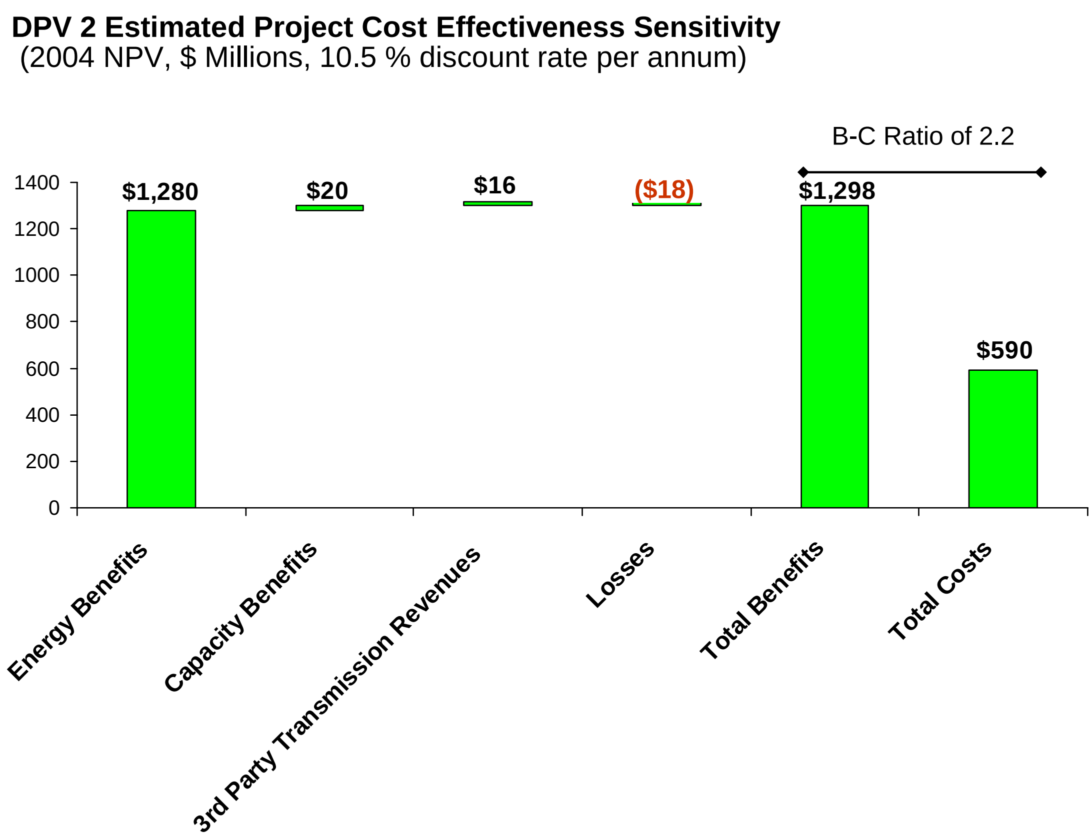
In conclusion, DPV2 is cost-effective with a benefit-to-cost ratio of almost 3:1. This analysis utilized a reasonable set of assumptions, and accounted for the uncertainty of major economic drivers. For example, this analysis included the uncertainty of natural gas prices, load forecasts, and available hydro generation. Major transmission operational constraints into California were also modeled. In addition, the analysis attempted to quantify all reasonable and realistic costs and benefits to CAISO ratepayers. For example, costs of west of Devers substation, voltage support devices, and increased losses due to DPV2 were all captured. To be thorough, benefits of increased transmission revenues and a transmission capacity value were also estimated. After considering all costs and benefits and uncertainty of major economic drivers, DPV2 appears to be a cost effective project for CAISO ratepayers.

f) DPV2 Cost Effectiveness with Future Benefits Held Below Inflation or at Inflation:

As a sensitivity to the Project Evaluation analysis above in section III(D), we recalculated DPV2's cost effectiveness under the assumption that future benefits are held flat at 2012 levels. The 2004 NPV results shown in Figure 6 indicate DPV2's benefits-to-cost ratio is still robust at 2.2:1. In section III(D)(2)(a), we stated that results shown in Figure 5 included the assumption that benefits were held to zero real inflation beyond 2012. This assumption seems reasonable as long as Arizona will continue to have favorable characteristics that support construction of new generating stations. These characteristics include lower costs associated with labor, natural gas, land, permitting, and taxes. A further consideration is that DPV2 capacity may attract new generation development.

Synthesizing the results of holding future benefits flat or at inflation, we expect DPV2's benefit-to-cost ratio to be around 2:1 to 3:1; depending upon which economic assumptions beyond 2012 are employed.

Figure 6 – Cost-Effectiveness Sensitivity of DPV2



g) DPV2 Cost Effectiveness Range (2004 NPV of revenue requirements):

Thus far, DPV2's cost-effectiveness has been shown to have total benefits ranging from $1,300 million to $1,700 million (rounded) depending upon future escalation assumptions, and transmission line flows held at their operational limits. SCE also determined benefits where transmission lines flows could reach their thermal limits. These benefits total about $870 million. With this range of benefits project costs of $590 million, the following figure was developed. SCE believes that DPV2's benefit-to-cost ratio ranges from about 1.5:1 to 3:1 depending upon assumptions used. SCE believes assumptions used to determine the 3:1 benefit-to-cost ratio are the most realistic.

Figure 7 – DPV2's Range of Cost-Effectiveness

Benefit-to-Cost Ratios
(2004 NPV of Revenue Requirements, $ Million)

		Cost $590
Benefits w/o SCIT	$870	1.5
Benefits with SCIT and zero inflation	$1,300	2.2
Benefits with SCIT	$1,700	2.9

h) Potential Benefits Not Quantified:

Determining all the benefits that new transmission facilities accrue to ratepayers is a complex undertaking. Part of this complexity is identifying all possible benefits transmission facilities provide. The discussion thus far has quantified a reasonable set of potential benefits, but it is not a comprehensive list. Other potential benefits not quantified in this report, but which could increase DPV2's ratepayer benefits include:

- **Emergency value** – a new transmission line such as DPV2 could provide benefits during an emergency outage of another major import line or generating facility. For instance, if fire or an earthquake disables lines from the Pacific Northwest into California, then a line importing power from the southwest, such as DPV2, would provide benefits above what is quantified in this report. A similar emergency value could accrue during the outage of generation located in southern California.
- **Outcome of current generation projects** – the base case used in this DPV2 analysis includes Mohave generating station out-of-service, and San Onofre Generating Station and Mountainview in-service. Past studies by SCE and CAISO indicate the benefits

of DPV2 increase if Mohave operates while DPV2 is in service. If San Onofre does not have its steam generators replaced, then there is likelihood that DPV2 would become a critical part of meeting customers' needs in Southern California since more imports would be required to serve California load. If for some unknown reason Mountainview is not completed, the benefits of DPV2 will increase.

- **New generation development** – developing the DPV transmission corridor could attract new generation development east of Devers substation, such as in the Blythe area, providing additional supply to the California energy market. If it does, then DPV2's benefits should increase due to increased access to this new low cost generation.
- **Interconnection support** – The addition of DPV2 is expected to provide up to 1200 MW of additional import transmission capacity. In our estimation of DPV2's benefit-to-cost ratio we have quantified access to existing generation markets, which had the effect due to increased transmission infrastructure to allow generators to compete and enabled a more liquid and competitive electricity market. We have not attempted to quantify other potential benefits such as increased generation reliability, replacement for aging power plants, fuel diversity, reserve sharing or power exchanges that may occur over the life of DPV2.
- **Market Power** – DPV2 may provide benefits in the form of reducing the potential for generators to exercise market power. DPV2 helps increase the quantity of generation and number of suppliers to serve California markets and should help to increase competitive pressure on generators. This, in turn, should help to reduce the ability for generators to exercise market power.

IV. Appendix A – Production Simulation

A. Production Simulation

SCE used a production simulation model[31] to forecast market clearing prices for this cost-effectiveness analysis. The model simulates the entire Western Electricity Coordinating Council (WECC) region for development of Market Clearing Prices (MCPs) by WECC transmission area. The production simulation model does the following:

- Simulates the dispatch of generation resources across the entire WECC region.
- Economically dispatches lowest cost generation to match load.
- Aggregates loads and generation into zonal markets.
- Interconnects zones by aggregating transmission lines between zones.
- Performs hourly simulation.
- Computes supply curves and Market Clearing Prices, by hour and develops various load and resource reports. Market Clearing Prices are marginal energy prices, and do not reflect market prices with profit.

Typically, a pure economic dispatch production simulation understates a transmission project's benefits because it does not capture the impact of generation that is dispatched for purely non-economic purposes, such as reliability purposes. In a pure economic dispatch, the generation supply curve is optimized for lowest costs. When generation is dispatched for reliability reasons, it changes the energy supply curve to something slightly more costly than a predetermined economically optimized dispatch, thus increasing, total generation costs.

The base case modeling for the DPV2 analysis used SCE's April 15, 2003 long term Preferred resource plan, which includes: Mountainview (a new combined cycle generating facility), a significant increase in investments in energy efficiency and demand response, the assumed shutdown of the Mohave coal plant, and the addition of sufficient renewables to meet or exceed the 20% Renewable Portfolio Standard.

Two types of simulations were performed for DPV2's analysis: deterministic and stochastic. The deterministic analysis was performed using a base set of assumptions regarding loads, natural gas prices, and the availability of generating plants to meet customer needs. Deterministic analysis is useful for understanding a single set of input forecasts, but does not reflect the impact of uncertainty. Stochastic analysis models the uncertainty associated with different parameters. In the stochastic analysis, SCE included uncertainties associated with a) load forecasts, b) natural gas prices, and c) hydro generation variability. In addition, the analysis reflected the impact of random forced outages of generation units. Stochastic analysis captures the value of low

[31] SCE utilized Henwood Energy Services MARKETSYM production model for its analysis of DPV2.

probability events that can have an impact on an outcome. Below are graphs of the base, high, and low forecasts of load, and natural gas prices used in this analysis at the 90%, 50% and 10% confidence levels.

Figure 8 – CAISO Total Load - Monthly Confidence Intervals

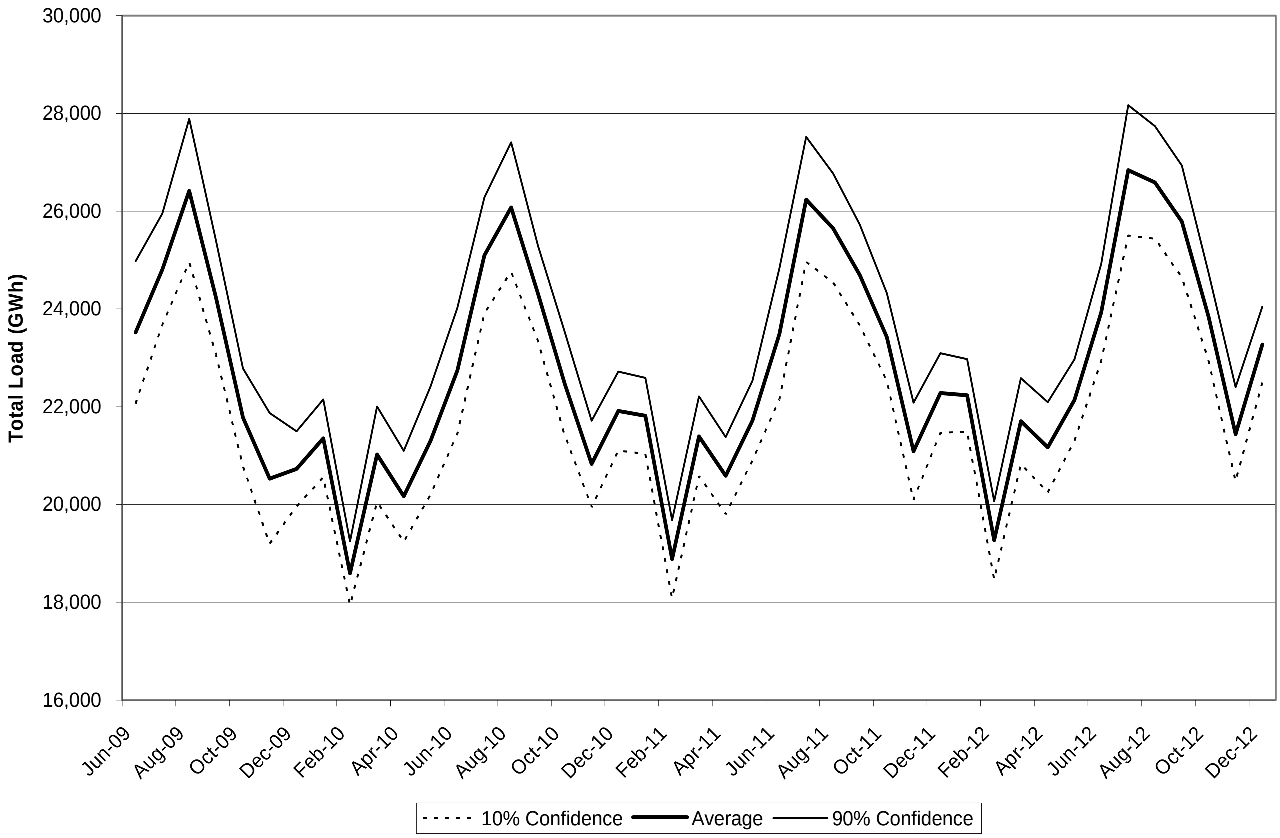
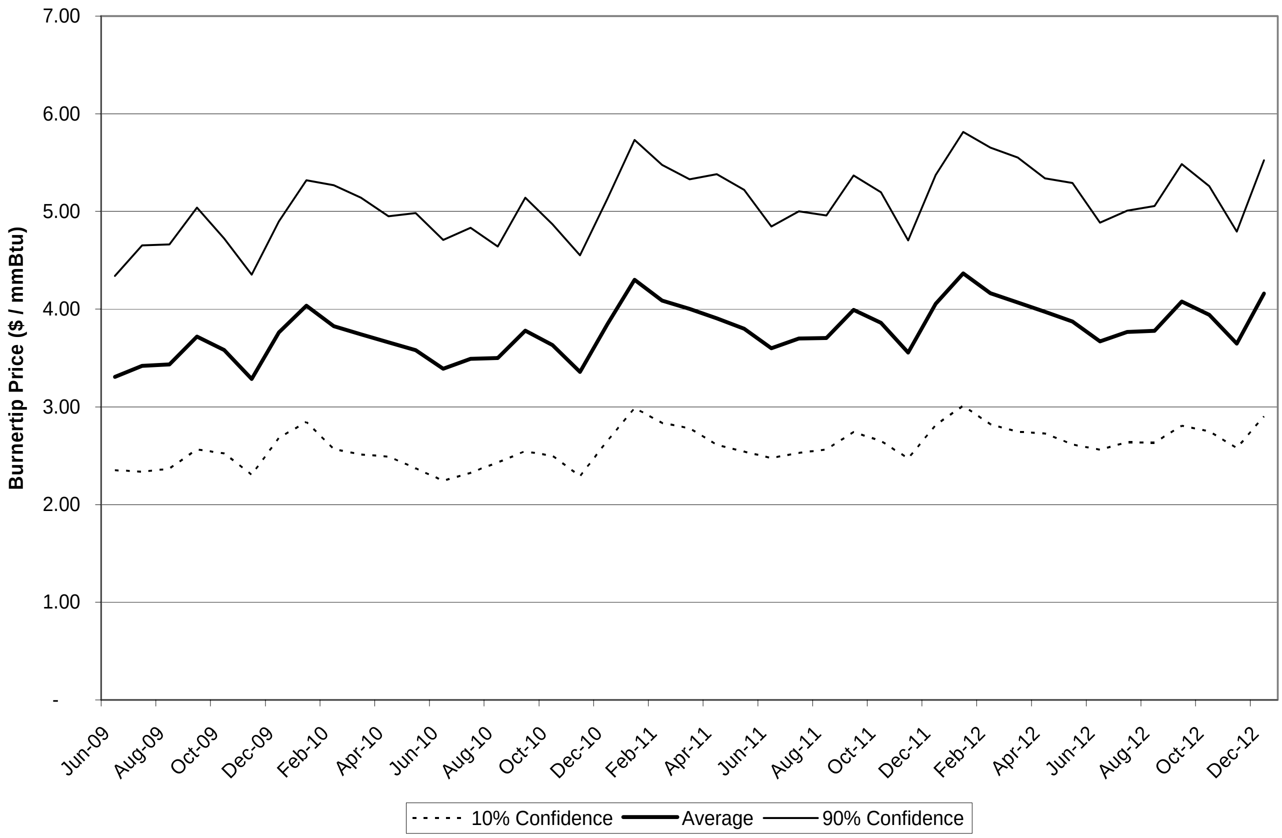


Figure 9 – Southern California Burnertip Natural Gas Price – Monthly Confidence Intervals



Other assumptions used in the production simulation are best explained by describing the modeling process used to approximate the relevant market in which DPV2 will operate. The model simulated the interconnected electrical system in the WECC (Western Electricity Coordinating Council) region by dividing the WECC's region into 25 market zones and 42 transmission paths between zones, shown in Figure 10 as a Deterministic Topology. Within this WECC model, the California electrical market is simulated by eight zones and 17 inter-zonal paths, and SCE's service territory is modeled by one zone with six inter-zonal paths. As a result, the electrical systems in California and SCE's territory are effectively modeled to determine resource requirements. Two definitions are in order: paths represent the aggregate transfer capability due to all parallel transmission lines operating between zones, and zones represent major load/generation areas. This topology of zones and paths provides a realistic framework in which to analyze transmission congestion impacting resource planning and the effects proposed transmission additions would have upon such congestion.

New transmission additions or changes in installed generation located within the zones can have a large impact on production results, so SCE used criteria which included only highly likely projects and filtered out speculative projects. New transmission facilities are only added if they affect the modeling production topology, construction is fairly certain[32], and ratings are more or less defined. Lines affect the topology if they can transmit power between zones, so new intra-zone transmission facilities would not be modeled. Some indicia that the line will be constructed (such as an outlay of substantial investment) are required to filter out speculative lines. New transmission lines require a rating to be provided by the WECC or the project sponsor who has conducted studies in support of the project's rating. Finally, utility specific projects such as DPV2 are added. For this analysis, seven new transmission projects meet these criteria and are shown in Appendix B.

To add generation to the base case, SCE also used other screening criteria. To be included, a generating facility must be either substantially constructed, and have financing completed, or be an investor owned or municipality utility project. SCE also added generation if public data reasonable supported such an addition. Appendix C provides the list of new generating facilities meeting these criteria which add a net amount of 25,000 MW of generation to WECC area, and about 6,500 MW in the Arizona and Nevada zones in the base case. New generation facilities at a specific site are netted against those facilities retired. The criteria used to remove or retire generation from the production simulation database are:

- Specific published retirement dates,
- Reach a life of 55 years or,
- Retirements due to air quality restrictions
- Consistency with California Commission planning assumptions

Appendix D provides a list of generating stations retired in the base case.

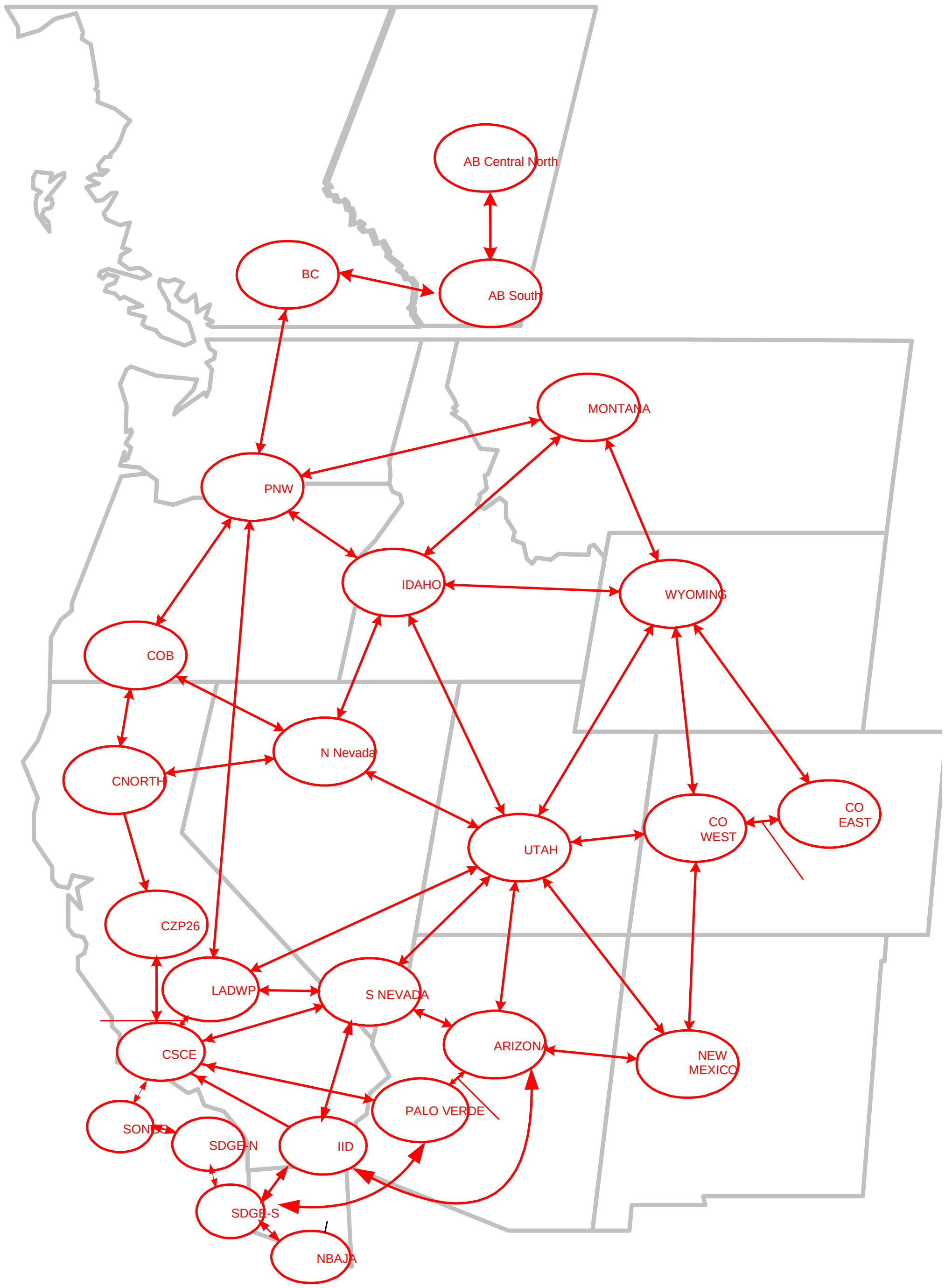
Other production simulation attributes include:

- WECC and CAISO transmission operational[33] and thermal ratings are enforced.
- Demand response programs are included in load forecasts
- Contracts between generators and load entities are not modeled.
- Substransmission line losses are accounted for in loads.

[32] To be fairly certain, entities sponsoring new transmission must make affirmative steps toward construction such as entering projects in the WECC rating process, making monetary investments like purchasing land or major facilities, or applying for regulatory permits necessary to construct.

[33] Thermal ratings were enforced for deterministic analysis, operational transmission rating of the Southern California Import Transmission nomogram was enforced in stochastic analysis.

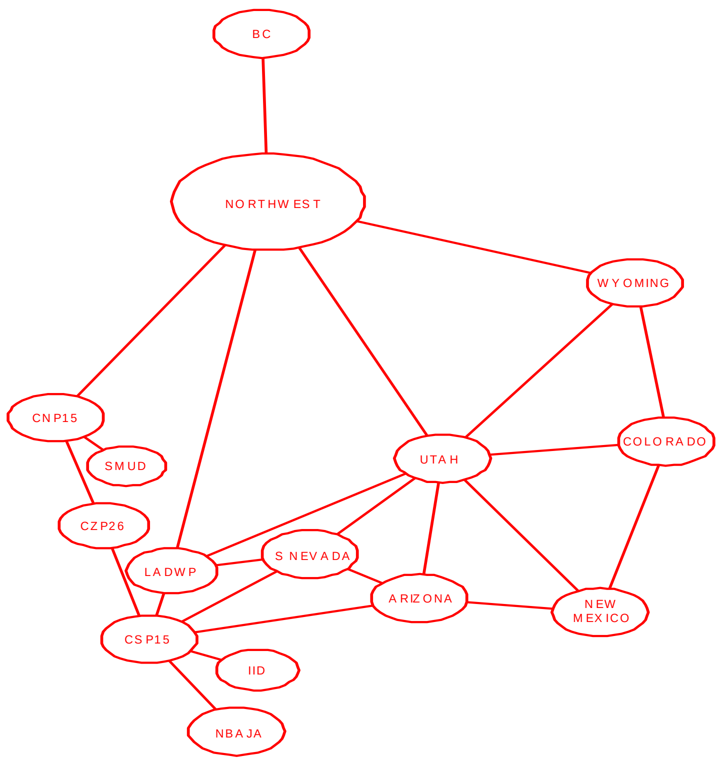
Figure 10 – Deterministic Topology



Production simulation outputs include production costs, Market Clearing Prices (MCP), total air emissions, and Energy Not Served (ENS).

These MCPs are calculated using a stochastic production module to take into account the uncertainty and volatility of important input assumptions (available hydro generation, natural gas prices, and magnitude of demand)[34]. The topology of zones and paths used in stochastic analysis is shown below in Figure 11. As can be seen, the zones and paths in California are largely unaffected by the reduction, rather the zones in neighboring states have been condensed.

Figure 11 – 15 Zone Stochastic Topology



[34] Henwood's MARKETSYM stochastic module.

B. Network Modeling

SCE's zonal model is a reasonable characterization of the WECC network. Figures 10 and 11 above demonstrate that the model SCE utilized appropriately captures transmission paths entering California from the southwest. These paths represent all major transmission lines capable of importing energy into California. It is also important to sufficiently model the California energy market since benefits are measured for CAISO ratepayers within California. Again, Figures 10 and 11 above illustrate numerous zones used to forecast California market prices. These zones represent all generation supply and loads in California. In addition to this zonal representation, SCE also provides complementary network representation indicating estimate power flows in Appendix A of the DPV2 Technical report.

C. Southern California Import Transmission Nomogram

Transmission lines can have operational limits which are lower than their maximum ratings[35]. Transmission lines importing energy into southern California are operated according to the Southern California Import Transmission (SCIT) nomogram. A nomogram is a chart showing the operational limits of a set of particular lines. The existing Devers-Palo Verde No. 1 – 500 kV transmission line is one of the lines whose rating is governed by the SCIT nomogram. DPV2's capability will also be governed by the SCIT nomogram once it is built. Since transmission power flows are managed by nomograms such as the SCIT, it is necessary to capture these operational limits in the DPV2 analysis. The production simulation used in the DPV2 analysis incorporated the current and expected[36] SCIT operational limits on applicable transmission lines.

MarketSym, the production simulation used for the DPV2 analysis, can be programmed to change the capability on a single path, but does not have the capability to change a particular transmission line's capability based upon the flow of another path[37]. The latter is needed to precisely model nomograms. Since, MarketSym does not have this capability; a new method was devised to estimate the energy flow relationship between SCIT transmission lines. The new method determined the maximum flow on SCIT lines by examining daily peak power flows for each SCIT line over a five year history (1998-2002). Based on historical flow levels, the line ratings were reduced such that the aggregate line limits totaled the existing SCIT operational

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[35] Line Rating is the WECC approved non-simultaneous capacity of the line. Line capability reflects adjustments to the Line Rating due to operational limits.

[36] Revised SCIT limits were estimated for new facilities such as DPV2 and Series Capacitor Upgrades project.

[37] For example, the rating on path A, cannot be automatically changed based upon the flows on Path B.

limit. This reduction was achieved by limiting line flow at the 95th percentile of historical flows, and an additional pro-rata reduction to certain paths[38]. MarketSym was then programmed with these flow limits to represent the operational limits of the SCIT nomogram for existing transmission paths and estimated SCIT values[39] for new facilities yet to be constructed. This method is a reasonable approach, since it is based upon historical flows, and attempts to assure that the aggregate line flows are within the SCIT operating limit.

[38] SCIT ratings for new projects such as upgrading series capacitors or constructing DPV2 were estimated using engineering analysis.

[39] New facilities which increase available transmission capacity are expected to increase operational limits, such as the SCIT nomogram.

V. Appendix B - Transmission Additions to Base Case

		Non-Simultaneous Ratings		
Utility Link Name	**Change Date**	**Old Rating (MW)**	**New Rating (MW)**	**Note**
Palo Verde to Phoenix	Jun-04	6,200	7,700	APS/SRP Southwest Valley Project
				Upgrade in direction Palo Verde to Phoenix only
PSE portion of West of Hatwai	Nov-04	84	105	Addition of Bell-Grande Coulee 500kv line
BPA portion of West of Hatwai	Nov-04	981	1,226	Addition of Bell-Grande Coulee 500kv line
PacifiCorp UT to SPPCO	May-05	220	440	Falcon-Gonder Project
SPPCO to PacifiCorp UT	May-05	80	235	Falcon-Gonder Project
Miguel Mission	Jun-05	1,690	2,250	Miguel Mission
Palo Verde to San Diego	Jun-06	1,133	1,283	Path 49 Series Capcacitor Upgrades Project
Palo Verde to SCE	Jun-06	1,550	1,718	Path 49 Series Capcacitor Upgrades Project
Southern Nevada to LADWP	Jun-06	3,823	3,905	Path 49 Series Capcacitor Upgrades Project
Arizona to Southern Nevada	Jun-06	4,634	4,802	Path 49 Series Capcacitor Upgrades Project
Southern Nevada to Arizona	Jun-06	4,785	4,953	Path 49 Series Capcacitor Upgrades Project
Devers Palo Verde	Jun-09	1,718	2,918	Devers Palo Verde II

VI. Appendix C - Generation Additions to the base case.

Note: Generic CCGT and GT additions have been included to maintain reasonable reserve levels in the noted geographical areas.

Unit Name	Unit No	Installation Date	Unit Type	Max Rating	Full Load HR	TA
Calgary Energy Cntr	1	4/1/2003	CCDF	300	7280	AB_S
Pincher Creek	1	10/1/2003	WT	37.296	10000	AB_S
GenCC_AB_S06	1	1/1/2006	GenCC	245	7280	AB_S
GenCC_AB_S08	1	1/1/2008	GenCC	245	7180	AB_S
GenCC_AB_S09	1	1/1/2009	GenCC	245	7180	AB_S
GenCCX_AB_S10	1	1/1/2010	GenCC	245	7180	AB_S
GenGT_AB_S12	1	1/1/2012	GenGT	180	10500	AB_S
GenGT_AB_S12	2	1/1/2012	GenGT	180	10500	AB_S
Foster Creek	1	3/1/2003	CG	66	8000	ABCN
McBride	1	9/1/2003	WT	12.7	10000	ABCN
McBride	2	12/1/2003	WT	13.6	10000	ABCN
GenGT_ABCN12	1	1/1/2012	GenGT	180	10500	ABCN
West Phoenix	5a	6/1/2003	CCDF	265	7380	Arizona
West Phoenix	5b	6/1/2003	CCDF	265	7380	Arizona
Santan Exp CC	1	6/1/2005	CCDF	275	7380	Arizona
Santan Exp CC	2	6/1/2005	CCDF	275	7380	Arizona
Santan Exp CC	3	6/1/2005	CCDF	275	7380	Arizona
GenGT_Ariz12	1	1/1/2012	GenGT	180	10500	Arizona
GenCC_BC05	1	1/1/2005	GenCC	245	7100	BC
GenCC_BC07	1	1/1/2007	GenCC	245	7280	BC
GenCC_BC07	2	1/1/2007	GenCC	245	7280	BC
GenCC_BC08	1	1/1/2008	GenCC	245	7180	BC
GenCC_BC08	2	1/1/2008	GenCC	245	7180	BC
GenCC_BC08	3	1/1/2008	GenCC	245	7180	BC
GenCC_BC08	4	1/1/2008	GenCC	245	7180	BC
GenGT_BC08	1	1/1/2008	GenGT	180	10500	BC
GenGT_BC08	2	1/1/2008	GenGT	180	10500	BC
GenGT_BC08	3	1/1/2008	GenGT	180	10500	BC
GenGT_BC08	4	1/1/2008	GenGT	180	10500	BC
GenCC_BC09	1	1/1/2009	GenCC	245	7180	BC
GenCCX_BC11	1	1/1/2011	GenCC	245	7180	BC
GenCCX_BC11	2	1/1/2011	GenCC	245	7180	BC
Wolfskill	1	1/1/2003	GT	45	10500	CNP15
Los Esteros Critical	1	3/1/2003	GT	45	10500	CNP15
Los Esteros Critical	2	3/1/2003	GT	45	10500	CNP15
Riverview Energy	1	3/30/2003	GT	45	10500	CNP15
Tracy Peaker	1	4/1/2003	GT	84.4	11000	CNP15
Tracy Peaker	2	4/1/2003	GT	84.4	11000	CNP15
Tracy Peaker	3	4/1/2003	GT	84.4	11000	CNP15
Woodland CC	2	5/1/2003	CCDF	80	8311	CNP15
Pico	1	1/1/2005	GT	160	10184	CNP15
Consumnes River	1	3/15/2005	CC	250	7180	CNP15
Consumnes River	2	3/15/2005	CC	250	7180	CNP15
Metcalf Energy	1a	6/1/2005	CCDF	289.4	7360	CNP15
Metcalf Energy	1b	6/1/2005	CCDF	289.4	7360	CNP15
San Fran Airport	1	6/1/2005	GT	160	10184	CNP15

Unit Name	Unit No	Installation Date	Unit Type	Max Rating	Full Load HR	TA
San Fran Airport	2	6/1/2005	GT	160	10184	CNP15
Kings River Peaker	1	7/1/2005	GT	160	10184	CNP15
Walnut CC	1	3/1/2006	CC	250	7180	CNP15
GenGT_CNP112	1	1/1/2012	GenGT	180	10500	CNP15
Blue Spruce Energy C	1	5/1/2003	GT	155	10850	CO_East
Blue Spruce Energy C	2	5/1/2003	GT	155	10850	CO_East
Front Range	1a	5/1/2003	CC	240	7100	CO_East
Front Range	1b	5/1/2003	CC	240	7100	CO_East
Rocky Mountain Energ	1a	5/1/2004	CCDF	300.5	7280	CO_East
Rocky Mountain Energ	1b	5/1/2004	CCDF	300.5	7280	CO_East
GenGT_CO_E12	1	1/1/2012	GenGT	180	10500	CO_East
GenGT_CO_W12	1	1/1/2012	GenGT	180	10500	CO_West
NewRen07	1	1/1/2003	GE	350	10000	CSCE
NewRen07	2	1/1/2003	GE	350	10000	CSCE
THUMS Long Beach	1	2/15/2003	CG	47	8000	CSCE
High Desert Power	1a	6/1/2003	CCDF	250	7400	CSCE
High Desert Power	1b	6/1/2003	CCDF	250	7400	CSCE
High Desert Power	1c	6/1/2003	CCDF	250	7400	CSCE
Agua Mansa	1	7/1/2003	GT	48	9700	CSCE
Huntington Beach	4M	8/1/2003	ST	225	10396	CSCE
Glenarm Expansion	3	9/1/2003	GT	47	9700	CSCE
Glenarm Expansion	4	9/1/2003	GT	47	9700	CSCE
Vernon GT	1	5/1/2005	GT	160	10184	CSCE
Mountainview CC	1a	1/1/2006	CCDF	255	7220	CSCE
Mountainview CC	1b	1/1/2006	CCDF	255	7220	CSCE
Mountainview CC	2a	1/1/2006	CCDF	255	7220	CSCE
Mountainview CC	2b	1/1/2006	CCDF	255	7220	CSCE
Elk Hills CC	1	3/1/2003	CCDF	275	7360	CZP26
Elk Hills CC	2	3/1/2003	CCDF	275	7360	CZP26
Sunrise Power CC	1a	7/1/2003	CC	280	7180	CZP26
Sunrise Power CC	1b	7/1/2003	CC	280	7180	CZP26
Pastoria CC	1a	6/1/2007	CC	250	7180	CZP26
Pastoria CC	1b	6/1/2007	CC	250	7180	CZP26
Pastoria CC	1c	6/1/2007	CC	250	7180	CZP26
GenGT_Idah12	1	1/1/2012	GenGT	180	10500	Idaho
NewRen02	1	1/1/2003	GE	350	10000	IID
NewRen02	2	1/1/2003	GE	350	10000	IID
Mesquite Lake	1	4/1/2003	CG	13.1	12500	IID
Salton Sea #6	1	7/1/2005	GE	185	21000	IID
Valley LADWP CC	1A	6/1/2003	CCDF	264.25	7360	LADWP
Valley LADWP CC	1B	6/1/2003	CCDF	264.25	7360	LADWP
Haynes Repowering	1a	12/1/2004	CC	287.5	7180	LADWP
Haynes Repowering	1b	12/1/2004	CC	287.5	7180	LADWP
Magnolia CC	1	3/1/2005	CC	250	7180	LADWP
First Megawatts CC	1A	7/1/2003	CC	120	7438	Montana
First Megawatts CC	1B	7/1/2003	CC	120	7438	Montana
Thompson River	1	12/1/2003	CG	10	9540	Montana
GenGT_Mont12	1	1/1/2012	GenGT	180	10500	Montana
Presco Rye Patch	1	1/1/2003	GE	12	23924	N Nevada
GenGT_N Ne12	1	1/1/2012	GenGT	180	10500	N Nevada
La Rosita (Azteca)	1a	7/1/2003	CC	295	7200	NBAJA
La Rosita (Azteca)	1b	7/1/2003	CC	295	7200	NBAJA
Pyramid Power Plant	1	4/1/2003	GT	38	9700	NewMexico

Unit Name	Unit No	Installation Date	Unit Type	Max Rating	Full Load HR	TA
Pyramid Power Plant	2	4/1/2003	GT	38	9700	NewMexico
Pyramid Power Plant	3	4/1/2003	GT	38	9700	NewMexico
Pyramid Power Plant	4	4/1/2003	GT	38	9700	NewMexico
GenGT_NewM12	1	1/1/2012	GenGT	180	10500	NewMexico
Goldendale	1	7/1/2003	CC	253	7100	Northwest
SP Newsprint	1	7/1/2003	CG	35	8000	Northwest
Chehalis CC	1a	11/1/2003	CC	260	7100	Northwest
Chehalis CC	1b	11/1/2003	CC	260	7100	Northwest
GenCC_Nort09	1	1/1/2009	GenCC	245	7180	Northwest
GenCC_Nort09	2	1/1/2009	GenCC	245	7180	Northwest
GenCC_Nort09	3	1/1/2009	GenCC	245	7180	Northwest
GenCCX_Nort10	1	1/1/2010	GenCC	245	7180	Northwest
GenCCX_Nort10	2	1/1/2010	GenCC	245	7180	Northwest
GenCCX_Nort10	3	1/1/2010	GenCC	245	7180	Northwest
GenCCX_Nort10	4	1/1/2010	GenCC	245	7180	Northwest
GenCCX_Nort10	5	1/1/2010	GenCC	245	7180	Northwest
GenCCX_Nort10	6	1/1/2010	GenCC	245	7180	Northwest
GenCCX_Nort11	1	1/1/2011	GenCC	245	7180	Northwest
GenCCX_Nort11	2	1/1/2011	GenCC	245	7180	Northwest
GenCCX_Nort11	3	1/1/2011	GenCC	245	7180	Northwest
GenCCX_Nort12	1	1/1/2012	GenCC	245	7180	Northwest
GenGT_Nort12	1	1/1/2012	GenGT	180	10500	Northwest
GenGT_Nort12	2	1/1/2012	GenGT	180	10500	Northwest
GenGT_Nort12	3	1/1/2012	GenGT	180	10500	Northwest
Gila River	1a	4/1/2003	CCDF	293.5	7380	PV
Gila River	1b	4/1/2003	CCDF	293.5	7380	PV
Gila River	2a	5/1/2003	CCDF	293.5	7380	PV
Gila River	2b	5/1/2003	CCDF	293.5	7380	PV
Gila River	3a	6/1/2003	CCDF	293.5	7380	PV
Gila River	3b	6/1/2003	CCDF	293.5	7380	PV
Harquahala	1a	6/1/2003	CC	260	7200	PV
Harquahala	1b	6/1/2003	CC	260	7200	PV
Harquahala	2a	6/1/2003	CC	260	7200	PV
Harquahala	2b	6/1/2003	CC	260	7200	PV
Mesquite CC	1	6/1/2003	CC	312.5	7200	PV
Mesquite CC	2	6/1/2003	CC	312.5	7200	PV
Gila River	4a	8/1/2003	CCDF	293.5	7380	PV
Gila River	4b	8/1/2003	CCDF	293.5	7380	PV
Mesquite CC	3	11/1/2003	CC	312.5	7200	PV
Mesquite CC	4	11/1/2003	CC	312.5	7200	PV
Apex Industrial	1a	3/1/2003	CC	250	7200	S Nevada
Apex Industrial	1b	3/1/2003	CC	250	7200	S Nevada
Blythe	1a	3/1/2003	CC	260	7200	S Nevada
Blythe	1b	3/1/2003	CC	260	7200	S Nevada
Reliant Bighorn	1a	10/1/2003	CC	290	7380	S Nevada
Reliant Bighorn	1b	10/1/2003	CC	290	7380	S Nevada
Silverhawk CC	1	6/1/2005	CCDF	275	7380	S Nevada
Silverhawk CC	2	6/1/2005	CCDF	275	7380	S Nevada
GenGT_S Ne12	1	1/1/2012	GenGT	180	10500	S Nevada
SDGE GenCCGT 1*	1a	6/1/2006	CCDF	261	7360	SDGEN
SDGE GenCCGT 1*	1b	6/1/2006	CCDF	261	7360	SDGEN
SDGE GenCCGT 2*	1	6/1/2007	CCDF	272.5	7389.7	SDGEN
SDGE GenCCGT 2*	2	6/1/2007	CCDF	272.5	7389.7	SDGEN
La Rosita (Baja)	2	6/1/2003	CC	310	7180	SDGES
La Rosita (Azteca)	1c	7/1/2003	CC	160	7180	SDGES

Unit Name	Unit No	Installation Date	Unit Type	Max Rating	Full Load HR	TA
TDM CC	1	8/1/2003	CCDF	300	7360	SDGES
TDM CC	2	8/1/2003	CCDF	300	7360	SDGES
GenCCX_CSDG12	1	1/1/2012	GenCC	245	7180	SDGES
GenCCX_Utah12	1	1/1/2012	GenCC	245	7180	Utah
GenGT_Utah12	1	1/1/2012	GenGT	180	10500	Utah
Wygen	1	3/1/2003	ST	80	10000	Wyoming

* Specific generation resource additions are representative of reasonable expectations in this region

VII. Appendix D - Generation Retirements in the base case.

Unit Name	Unit No	Retirement Date	Unit Type	Max Rating	Full Load HR	TA
Medicine Hat	7	1/1/2008	ST	30	10742	AB_S
Wabamun	1	1/1/2004	ST	67	14246	ABCN
Wabamun	2	1/1/2004	ST	56	14840	ABCN
Wabamun	4	1/1/2010	ST	280	11740	ABCN
Rossdale	10	10/1/2010	ST	72	12739	ABCN
Rossdale	8	10/1/2010	ST	71	13384	ABCN
Rossdale	9	10/1/2010	ST	73	12948	ABCN
Kyrene	1	1/1/2007	ST	34	12383	Arizona
Kyrene	2	1/1/2009	ST	72	11134	Arizona
Saguaro	1	1/1/2009	ST	100	11195	Arizona
Saguaro	2	1/1/2010	ST	99	11702	Arizona
Agua Fria	1	1/1/2012	ST	114	9896	Arizona
Lytton Diesel	1	1/1/2006	IC	4	11000	BC
Pittsburg	3	10/1/2003	ST	154	10645	CNP15
Pittsburg	4	10/1/2003	ST	150	10623	CNP15
Hunters Point	4	1/1/2006	ST	163	10385	CNP15
Hunters Point	GT1	1/1/2006	GT	52	12813	CNP15
Pittsburg	1	1/1/2009	ST	163	11408	CNP15
Pittsburg	2	1/1/2009	ST	154	11017	CNP15
Humboldt Bay	1	1/1/2011	ST	53	12379	CNP15
Zuni	1	1/1/2003	ST	39	13630	CO_East
Trinidad	1-4	1/1/2005	IC	10	13000	CO_East
Arapahoe	3	1/1/2006	ST	45	11810	CO_East
Birdsall	1	1/1/2008	ST	16	13500	CO_East
Birdsall	2	1/1/2009	ST	17	13500	CO_East
Raton	4-5	1/1/2009	ST	12	14200	CO_East
Zuni	2	1/1/2009	ST	68	13440	CO_East
Arapahoe	4	1/1/2010	ST	111	10700	CO_East
W.N. Clark	1	1/1/2010	ST	17	10669	CO_East
Birdsall	3	1/1/2012	ST	23	13500	CO_East
Bullock	1-2	1/1/2007	ST	12	18000	CO_West
Cameo	1	1/1/2012	ST	24	12440	CO_West
Klamath Expansion	1	6/1/2004	GT	50	9700	COB
Klamath Expansion	2	6/1/2004	GT	50	9700	COB
Etiwanda	1	1/1/2003	ST	132	12746	CSCE
Etiwanda	2	1/1/2003	ST	132	12380	CSCE
Alamitos GT	7	12/31/2003	GT	147	18510	CSCE
Etiwanda	5	12/31/2003	GT	142	20006	CSCE
Redondo Beach	5	1/1/2009	ST	175	10345	CSCE

Unit Name	Unit No	Retirement Date	Unit Type	Max Rating	Full Load HR	TA
Redondo Beach	6	1/1/2012	ST	175	12000	CSCE
Sunrise Power	1	4/1/2003	GT	160	10184	CZP26
Sunrise Power	2	4/1/2003	GT	160	10066	CZP26
Morro Bay	1	9/30/2003	ST	163	10443	CZP26
Morro Bay	2	9/30/2003	ST	163	10651	CZP26
El Centro	3	1/1/2012	ST	48	10619	IID
Grayson GT	7	1/1/2003	GT	21	12500	LADWP
Grayson GT	6	7/1/2003	GT	18	13000	LADWP
Haynes	4	11/1/2003	ST	222	9794	LADWP
Magnolia GT	5	12/31/2003	GT	22	14268	LADWP
Olive	3	12/31/2003	GT	24	14339	LADWP
Olive	4	12/31/2003	ST	31	14339	LADWP
Valley LADWP	1	4/15/2004	ST	95	11345	LADWP
Valley LADWP	2	4/15/2004	ST	95	10968	LADWP
Valley LADWP	3	4/15/2004	ST	163	10804	LADWP
Valley LADWP	4	4/15/2004	ST	160	10854	LADWP
Haynes	3	9/1/2004	ST	222	9705	LADWP
Magnolia	3	9/30/2004	ST	21.5	11827	LADWP
Magnolia	4	9/30/2004	ST	32	11100	LADWP
Grayson	3	1/1/2009	ST	19	13000	LADWP
Afton GT	1	10/1/2003	GT	135	11000	NewMexico
Los Alamos	1	1/1/2005	ST	5	14024	NewMexico
Los Alamos	2	1/1/2005	ST	4	14024	NewMexico
Los Alamos	3	1/1/2007	ST	9	13475	NewMexico
Rio Grande	6	1/1/2012	ST	48	11844	NewMexico
Pierce Power	1	1/1/2003	GT	154	9700	Northwest
Mohave	1	1/1/2006	ST	790	9771	S Nevada
Mohave	2	1/1/2006	ST	790	10123	S Nevada
Clark ST	1	1/1/2010	ST	42	11719	S Nevada
Clark ST	2	1/1/2012	ST	69	11260	S Nevada
Naval Station	1	1/1/2003	GT	29	14357	SDGEN
Naval Training Ctr	1	1/1/2003	GT	16	16239	SDGEN
North Island	1	1/1/2003	GT	22	14950	SDGEN
North Island	2	1/1/2003	GT	22	15220	SDGEN
South Bay	4	1/1/2003	ST	222	12461	SDGEN
South Bay	1	12/31/2008	ST	146	10567	SDGEN
South Bay	2	12/31/2008	ST	150	10259	SDGEN
Encina	1	1/1/2009	ST	104	11287	SDGEN
Encina	2	1/1/2011	ST	105	11428	SDGEN
Provo City	4	1/1/2004	ST	8	14500	Utah
Gadsby	1	1/1/2006	ST	60	12806	Utah
Gadsby	2	1/1/2007	ST	75	11734	Utah
Carbon	1	1/1/2009	ST	70	10235	Utah
Gadsby	3	1/1/2010	ST	100	10894	Utah
Carbon	2	1/1/2012	ST	105	10542	Utah
Osage	1	1/1/2003	ST	10	14700	Wyoming
Osage	2	1/1/2005	ST	10	14750	Wyoming
Osage	3	1/1/2007	ST	10	14400	Wyoming

Retirements shown herein are announced retirements or have a life expectancy of 55 years.

VIII. Appendix E – CAISO Requested Information

A. WECC Total Production Costs

The CAISO requested the change in WECC wide production costs to determine societal benefits of the project. Below is a figure showing the changes in total production costs that include generation fixed and variable costs, and costs of transmission losses, emissions, wheeling charges and energy not served. Total production costs were calculated for the WECC region with and without DPV2. Figure 12 shows constructing DPV2 reduces production costs by about $25 million per year (Real 2003). These estimates doe not include the other benefits described above and therefore do not represent a complete evaluation of DPV2.

Figure 12 – WECC Wide Production Costs (Real 2003 $M)

	2009	**2010**	**2011**	**2012**
Without DPVII	10,680.19	18,128.94	19,299.12	20,052.32
With DPVII	10,664.56	18,103.21	19,273.84	20,025.70
Net	**15.63**	**25.73**	**25.28**	**26.62**

B. Impact to Arizona

The CAISO requested data showing the impact to Arizona ratepayers. Below is a figure which includes estimates of consumer surplus, production surplus of Arizona utility owned generation, and transmission congestion revenues of Arizona transmission owners. Using stochastic analysis, constructing DPV2 was found to have a net negative impact of around $16 to $20 million per year to Arizona as shown in Figure 13 below. Generation plants locating in Arizona will stimulate the Arizona economy. For example, the Arizona economy is stimulated from the creation of new jobs due to generation plants, a secondary economic ripple effect the generation industry and employment have on other parts of the economy, and corresponding increased tax base.

Figure 13 – Arizona Producer and Ratepayer Benefits (Real 2003 $M)

	2009	2010	2011	2012
Consumer Surplus	(57.44)	(78.90)	(79.59)	(92.11)
URG Producer Surplus	45.33	63.07	63.69	73.29
Transmission Congestion Revenues	0.18	(0.17)	(0.09)	(0.21)
Net Impact	**(11.93)**	**(16.00)**	**(15.99)**	**(19.02)**