PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

September 24, 2001

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10/25/01

TO: PARTIES OF RECORD IN INVESTIGATION 00-11-001

This is the proposed decision of Administrative Law Judge (ALJ) Gottstein. It will be on the Commission's agenda at the next regular meeting 30 days after the above date. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Comments should be served by both electronic and U.S. mail on all appearances and the state service list in this proceeding. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages. Finally, comments must be served separately on the ALJ and the assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail, or other expeditious method of service.

/s/ LYNN T. CAREW
Lynn T. Carew, Chief
Administrative Law Judge

LTC:tcg

106952

Attachment

Decision **PROPOSED DECISION OF ALJ GOTTSTEIN** (Mailed 9/24/2001)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation into implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply.	Investigation 00-11-001 (Filed November 2, 2000)

INTERIM OPINION ON TRANSMISSION CONSTRAINTS: SOUTHERN CALIFORNIA LINK TO THE SOUTHWEST

(See Attachment 1 for List of Appearances.)

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ATTACHMENTS

INTERIM OPINION ON TRANSMISSION CONSTRAINTS: SOUTHERN CALIFORNIA LINK TO THE SOUTHWEST

1. Introduction and Summary[1]

We initiated this investigation in November 2000 to "identify and undertake those actions necessary to reduce or remove constraints on the state's existing electrical transmission and distribution system." (Public Utilities Code Section 399.15(a)(1) added by Assembly Bill (AB) 970 signed September 6, 2000.) In Phase 1 of this proceeding, we directed Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) to undertake 31 transmission projects to relieve system congestion by the summer of 2001 in specified areas of the state. (See Decision (D.) 01-03-077.)

We are addressing longer-term transmission planning issues during Phase 2 of this proceeding. Today's decision evaluates the need for a new Southern California link to Arizona, Nevada or Mexico ("the Southwest").

Based on the analysis presented on the record, we conclude that new transmission to the Southwest is not likely to be needed for reliability purposes before 2008. We reach this conclusion after evaluating the results and likelihood of numerous modeling scenarios and input assumptions presented in this proceeding. Our conclusions take account of recent updates to transmission transfer capability identified on the record. They also take account of potential bias in the reliability model utilized by the California Independent System

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[1] Attachment 2 explains each acronym or other abbreviation that appears in this decision.

Operator (ISO), SCE, SDG&E, and the California Energy Commission (CEC) in this proceeding. We will continue to monitor the reliability modeling efforts conducted through the ISO's Grid Coordinated Planning Process in order to update and confirm these results with the detailed power flow studies conducted during that process. To this end, we direct Energy Division to report to us on an ongoing basis if future power flow studies indicate a need for reliability purposes earlier than 2008.

Although the record is voluminous with modeling runs addressing the need for new transmission for reliability purposes, the parties to this proceeding did not assess the costs and benefits associated with building new transmission to the Southwest for "economic" reasons, i.e., to make less expensive power available to ratepayers. Instead, they propose to develop a methodology for this purpose via a joint Request for Proposals (RFP) process initiated by the ISO.

As discussed in this decision, we believe that the public interest is best served by evaluating the economic need of new transmission projects, and the appropriate allocation of costs among ratepayers and other beneficiaries, in this proceeding--where we can ensure that a public record is fully developed. To that end, we direct SCE, SDG&E, and PG&E to jointly file the results of the ISO / stakeholder RFP process within 15 days from the date that the consultant's final report is completed. The assigned ALJ will hold a PHC as soon as practicable thereafter to schedule evidentiary hearings on the economic need for new transmission to the Southwest.

With regard to testimony in this proceeding concerning needed in-state transmission upgrades, we have recently scheduled a separate set of evidentiary hearings on the net economic benefits to ratepayers of relieving two potential in-state transmission constraints in Southern California, including alternatives to address potential congestion west of Miguel.[2] Since the modeling efforts presented in this proceeding do not address in-state transmission constraints, no conclusions can be made from the record in this proceeding regarding the adequacy of the in-state transmission grid in the Southern California region.

Finally, we direct SDG&E to report on the status of discussions with the Comision Federale de Electricidad (CFE) or other entities regarding further upgrades to Path 45 that may involve ratepayer funding.

2. Procedural History

A prehearing conference (PHC) in Phase 2 was held on March 13, 2001, and a follow-up PHC conference call took place on March 27, 2001. On March 29, 2001, the Assigned Commissioner issued a ruling directing PG&E to file a separate application requesting a Certificate of Public Convenience and Necessity (CPCN) for Path 15 transmission upgrades (e.g., Los Banos-Gates), where there are constraints moving bulk power from Southern to Northern California. On April 3, 2001, the Commission issued D.01-04-007 directing PG&E to conduct studies of biological resources along Path 15 immediately.

The assigned ALJ established the scope of summer hearings in her ruling dated March 29, 2001. She directed SCE and SDG&E (collectively referred to as "the utilities") to file scenario analyses for evaluating the cost-effectiveness of potential transmission upgrades for a Southern California-Southwest link that included 1) alternative scenarios regarding generation growth, including likely sites for future generating facilities, and 2) load growth scenarios, including geographic demand patterns. The utilities were required to clearly set forth their

[2] See Administrative Law Judge's Ruling dated July 19, 2001.

methodology and input assumptions for projecting system benefits in terms of both decreased likelihood of outages and cost savings for purchased power. At the March 27 PHC and subsequent conference call, the ISO indicated that it would work with the utilities to produce the scenario analysis for the summer hearings.

In her March 29, 2001 ruling, the ALJ also discussed coordination with the Valley-Rainbow CPCN application filed on March 23, 2001 (A.01-03-036.) She clarified that processing of the CPCN application would not be delayed by consolidating it with this investigation. The CPCN application would be evaluated on a "stand-alone" basis, i.e., without presupposing any enhanced benefits from this project being augmented by a Southwest power link. However, if the Commission issued a final decision in this proceeding regarding the cost-effectiveness of a new transmission link to the Southwest, those determinations could be considered in the Valley-Rainbow CPCN proceeding.

The utilities, ISO and the CEC, referred to as the "Joint Parties," served joint opening testimony on May 18, 2001. Save Southwest Riverside County (SSRC) and Coral Power L.L.C. (Coral Power) served intervenor testimony on May 29, 2001. The Joint Parties served rebuttal testimony on June 8, 2001. Three days of evidentiary hearings were held, followed by opening briefs and reply briefs, upon which the matter was submitted on July 27, 2001.

3. Joint Study Methodology

Joint Parties evaluated the need for a Southwest power link for system reliability by utilizing a spreadsheet "matrix" methodology. This approach first calculates the arithmetic difference between projected loads and in-state generation resources (existing and new) to determine whether imports are needed to meet load. Then, it compares the quantity of required imports with available Southwest imports and the existing available transmission import capability to the Southwest. Existing firm exports and imports are also accounted for in the spreadsheet calculations. The spreadsheet then arithmetically determines if there is (1) a shortfall in available imports or (2) a shortfall in available transmission capacity, or both. These determinations were made for each year of the planning period, 2001 through 2011.

The matrix model was benchmarked against a detailed technical study of the Southern California-Southwest transmission system, entitled the "Southern California Long-Term Regional Transmission Study" (Southern CA Study). The study was conducted by the ISO, SDG&E, and SCE in the context of the ISO's annual grid planning process and was completed in February 2001. The study included a detailed power flow analysis that modeled the capability of the transmission system. It examined a single, conservative set of assumptions regarding the development of in-state generation resources. In particular, only one generating station (High Desert at approximately 700 megawatts (MW)) was added to the existing generation to model 2008 system conditions. The technical analysis demonstrated that, given the conservative scenario assessed, major improvements to transmission import capability would be needed to meet reliability requirements in Southern California in the year 2008.

Joint Parties compared the results of the Southern CA Study to the results of the matrix model, using similar assumptions concerning new in-state resources. Joint Parties concluded that the results were consistent, and therefore the matrix methodology was valid.

4. Modeling Scenarios and Input Assumptions

Joint Parties initially presented two scenarios in their testimony, a "Planning Scenario" and "Aggressive Generation Retirement and Outage

Scenario." The Planning Scenario represents the Joint Parties' preferred assumptions concerning retirements and outages. The Aggressive Generation Retirement and Outage Scenario uses alternate retirements and outages assumptions provided by the CEC in accordance with Energy Division's direction. Additional scenarios were prepared before the start of hearings at the request of the ALJ. The various scenarios are referred to throughout this decision as follows:

Scenario 1: Joint Parties' Planning Scenario (No Retirements)

Scenario 2: CEC's Alternate Retirement and Outages Assumptions

Scenario 3: Planning Scenario without Derating Transmission Capability

Scenario 4: CEC's Alternate Retirement and Outages Scenario without Derating of Transmission Capability

Scenario 5: CEC's Alternate Retirement and Outages Assumptions (Scenario 4) with Additional Retirements Beyond 2004

Within each scenario, various "cases" were presented using alternate load forecasts, alternate assumptions regarding in-state generation and new Southwest generation additions. These cases are described in greater detail below.

4.1 Load Forecast

In addition to a base load forecast, Joint Parties presented alternate cases that scale the base load forecast (1) up by 10%, (2) down by 10%, (3) up by 20% and (4) down by 20%.[3] In addition, Joint Parties presented an "average load" case defined as 65% of SCE's peak load and 54% of SDG&E's peak load.

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[3] There were also three variations of the base load forecast presented in the matrix analysis—one prepared by the utilities, one prepared by CEC and one representing a "utility average load case." Since the record in this proceeding indicates that these three

Footnote continued on next page

The load forecasts were based on a 1 in 5-year heat wave forecast. They include the service territories of SDG&E, SCE, and the City of Pasadena. Load forecasts from other municipal utilities that are served from SCE's transmission system (e.g., City of Vernon, Anaheim, Azusa, and Banning) were included in SCE's load forecast.

4.2 Existing In-State Generation

The Joint Parties presented two alternative cases for existing in-state generation, one developed by the utilities based on dependable generation levels available as of January 1, 2001, and one developed by the CEC based on nameplate capacity, which is usually higher than dependable capacity.

4.3 New Generation Additions in Southern California

Five alternate sets of assumptions were used for new in-state generation, 1) a utility maximum new in-state generation case, 2) a CEC maximum new in-state generation case, 3) a CEC medium new in-state generation case, 4) a CEC low new in-state generation case and 5) a very low new in-state generation case. All new in-state generation addition numbers were held constant after the year 2005.

The utilities based their forecasts of maximum new in-state generation on information they obtain from developers requesting interconnection studies. By 2004, the utilities estimate that approximately 18,750 MW of new in-state capacity will be available during the planning period.

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variations are relatively close, we use the CEC base load projection throughout our discussion and tables. See Reporter's Transcript (RT) at 18-24, Exhibit (Exh.) 17.

CEC based its maximum, medium and low cases based on the following status designations:

Status 1: Under construction or recently completed

Status 2: Regulatory approval from the CEC received

Status 3: Application under review by the CEC

Status 4: Starting application process before the CEC

Status 5: Press release only

The CEC's maximum new in-state generation case includes all known projects having CEC's status 1-5, which represents approximately 20,500 MW of new capacity by 2004. The medium new in-state generation case includes all projects having CEC's status 1-3 (6,500 MW). Joint Parties define the low new in-state generation case as all projects having CEC status 1-2 (5,050 MW).

The very low new in-state generation case is from the Southern CA Study described above. Specifically, this case assumes that 720 MW in new in-state capacity (coming on line in 2003) will be available during the planning period.

4.4 New Southwest Generation Additions

The new Southwest generation cases were 1) a maximum potential level available to Southern California and 2) a medium potential level available to Southern California. CEC presented the estimates for Arizona and Nevada, by starting with all projects under the 1-5 status designations listed above. For Arizona, this represents approximately 10,500 MW by 2004, increasing to 17,700 MW by 2007. For Nevada, CEC estimates that approximately 4,600 MW will be available by 2004, increasing to 6,000 MW by 2007. The maximum potential case assumed that 50% of these resources would materialize, while the medium case assumes that 20% would materialize.

For Mexico import capability, the Joint Parties present two sets of assumptions. One set was developed by the utilities, based on the number of projects in their interconnection queue. Projects are placed in the queue when SDG&E receives an application for an interconnection study from the project owner. The utilities estimate that approximately 2,000 MW will be available for import from Mexico by 2003, increasing to 2,550 MW by 2005. The other set of assumptions was developed by the CEC based on publicly released information. CEC estimates a similar amount of availability by 2003, with that level increasing to about 2,300 MW by 2007. The maximum potential case assumed that 100% of these resources would materialize, while the medium case assumes that 20% would materialize. All new out-of-state generation addition numbers are held constant after the year 2007.

4.5 Generation Retirements

The Joint Parties' Planning Scenario (Scenario 1) did not assume any retirements for the planning period, i.e., 2001 through 2011. Alternate assumptions for retirements were used for Scenarios 2, 4, and 5.

For Scenarios 2 and 4, Redondo Beach 5 and 6 and High Grove 1-4 are retired in 2002 because of their very high heat rates, for a total of 500 MW. These units have heat rates in the 13,400 to 14,700 British thermal units (Btu) per kilowatt hour (kWh) range, and are expected to be retired, according to CEC. This scenario also assumes that 15 emergency peaking units in SCE's and SDG&E's service territories (approximately 615 MW) would retire in 2003. Most of these units have been offered three-year operating permits with the possibility of extending operation beyond that date only upon the expenditure of significant money for pollution abatement. No retirements during the rest of the planning period were assumed.

For Scenario 5, CEC developed estimates of additional retirements beyond 2003, at the request of the ALJ. CEC identified specific plants with heat rates that would probably not be profitable if prices drop by 2004 due to the amount of new capacity projected to come on line in California, Nevada, and Arizona. This scenario projects additional retirements of 1,760 MW between 2004 and 2007.[4]

4.6 Generation Outages

Scenario 1 makes allowances for generation outages using ISO transmission planning standards, namely, that the most critical single generating unit (San Onofre's Unit 2 or 3) is out of service in combination with the most critical single transmission line. This represents 1,150 MW of outages in each year of the planning period.

Scenario 2 adds to this allowance additional outages to reflect a scenario that represents one day per summer probability. According to CEC, this is accomplished by assuming approximately 3,400 MW in outage allowances each year of the planning period, based on historical experience. To derive this level, CEC assumed that 15% of gas-fired capacity in SCE and SDG&E's service territory plus 7½% of the gas and coal-fired capacity in Kern County would be unavailable along with an outage at one of the San Onofre units.[5]

4.7 In-State Transmission Constraints

Joint Parties' matrix methodology addresses only links to out-of-state resources, and does not address whether in-state transmission upgrades are needed to maintain reliable operations.[6]

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[4] See RT at 282-290, Exhs. 11 and 30.

[5] RT at 273-280; Exh. 11.

[6] Exh. 1, p. 2, 19.

4.8 Derating of Transmission Capability

California's existing transmission system is capable of importing a total of 7,319 MW from the Southwest, over and above entitlements for the ISO controlled grid and other commitments. This is the figure generally used in the matrix spreadsheet to calculate the need for new transmission capacity under the various sets of load and resource assumptions. However, under the "very low generation" case, the Joint Parties reduce or "derate" this capability for the baseload, baseload plus 10%, and baseload plus 20% matrix calculations.

Joint Parties' contend that, without additional reactive voltage support, the system would be unable to transfer imports at the full 7,319 MW level when there is a large gap between in-state generation and loads.

Therefore, they argue that import capability should be derated in the matrix model for the "very low generation" case using the following formula:[7]

$$\text{Derated Capability} = \text{Import Capability} - \frac{(\text{Load Growth} - \text{New Generation})}{(\text{Load Growth})} \times (\text{Load Growth})$$

$$= \text{Import Capability} - \text{Load Growth} + \text{New Generation}$$

Accordingly, Joint Parties derate transmission import capability from 7,319 MW to approximately 3,100 MW by 2011 under the very low generation case using base load assumptions. For base load plus 10% and 20%, Joint Parties derate import capability to approximately 2,675 and 2,250 MWs, respectively.

5. Scenario Results

The results of the scenario analysis are summarized in Tables 1 and 2 appended to this decision. Table 1 presents the results for all cases generated

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[7] RT at 331

under the Joint Parties' Planning Scenario (Scenario 1), which assumes no generation retirements throughout the 2001-2011 planning period. Table 2 presents the results for scenarios that assume retirements during the planning period and a higher level of outages than the Joint Parties' Planning Scenario (Scenarios 2 and 5). Both tables also show the results of Scenarios 3 and 4, which remove transmission derating for selected cases. (See above.)

5.1 No Generation Retirements (Joint Parties' Planning Scenario)

A total of 48 cases were run under the Joint Parties' Planning Scenario to reflect various sets of assumptions concerning load, in-state ("internal") generation, and the availability of out-of-state ("external") generation resources for import. As indicated in Figure 1, 10 out of the 48 cases indicate a need for new transmission to the Southwest before the end of the planning period to maintain system reliability.

Specifically, transmission is needed under six cases that assume very low internal generation, i.e., that only 720 MW of new in-state generation will materialize over the planning period. Under the base load forecast, in the very low in-state generation case, additional transmission access to the Southwest is needed by 2008 for both the maximum and medium cases regarding available external resources. If the base load forecast is increased by10%, additional transmission import capability is required by 2005. If it is increased by 20%, then additional transmission is needed throughout the planning period. Transmission is also needed under the "low" and "medium" internal generation cases if the base load forecast is increased by 20%.

5.2 Retirements and Additional Outages Scenarios

Another 48 cases were run under Scenario 2, using the CEC's alternate assumptions concerning retirements and outages. As indicated in Table 2 and Figure 2, 16 out of the 48 cases indicate a need for increased import capability during the planning period. Figure 2 also illustrates that for two of these cases, there is insufficient external resources for import to meet all of the load demand within California, even under assumptions of "maximum" external resources.

Transmission is needed under all cases that assume very low internal generation, with the exception of the very lowest load assumptions (base load less 20% or average load). Transmission is also needed during the planning period under low and medium internal generation cases with base load plus 10% and 20%.

As discussed above, Scenario 2 assumes no retirements after 2003. If CEC assumptions concerning post-2003 retirements are used (Scenario 5), then the need for transmission is moved up 1-2 years in most of these 16 cases. (See Table 2.)

5.3 No Derating of Transmission Capability

The ALJ requested that Joint Parties produce the matrix spreadsheet results without derating transmission capability. As discussed above, transmission capability was derated for cases that assumed very low new in-state generation (720 MW) and a baseload, baseload plus 10% or baseload plus 20% load forecast. When derating is removed from these cases, the matrix results show a need for new transmission line generally 2-3 years later than the matrix results with derating. (See Tables 1 and 2.)

6. Economic Analysis

Joint Parties presented preliminary project cost estimates and described the economic factors to be considered in evaluating the need for new transmission from an economic, cost-benefit perspective. They conclude that a transmission project to upgrade access from Southern California to Arizona would likely involve 240 miles of new 500 kV transmission line and could cost between half to two billion dollars, depending on the ultimate cost of transmission line per mile. A transmission project to upgrade access from Southern California to Mexico would likely involve 100-190 miles of new 500 kV transmission line and could cost between one quarter to one and three quarters billion dollars depending on the route and the ultimate cost of transmission line per mile. These estimates do not include the cost of any upgrades to the in-state transmission system to ensure that the power imported could reach dense load centers.[8]

Joint Parties do not address whether this added transmission capability should be built from an economic perspective, e.g., to benefit from long-term electricity market prices, for the following reasons:

> "Deregulation of electricity supply has made it more difficult to accurately assess the economic need for a specific transmission line….When utilities exercised cost-based central dispatch of generation, transmission planning, including economic assessments, was relatively straightforward and the simulation of various generation costs was relatively simple. Now, however, without control over generation supplies or access to future generation or future regional market price data, neither the CA ISO nor utility transmission planners have a clear basis

[8] Exh. 1, pp. 27-28, 31-32.

> for determining whether and when to construct economic transmission additions.
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> "Modeling and simulation tools designed under the old paradigm can no longer be relied on to provide accurate estimates. New, more complex, simulation models that appropriately incorporate the complex dynamics of this deregulated environment are required. These tools are necessary to assess the likelihood and range of regional electricity price differentials and/or the effect of access to a larger market for electricity on Southern California electricity prices. Differences in electricity prices to Southern California consumers must then be compared against the cost of building, financing, operating and maintaining a new transmission line."[9]

Joint Parties recommend that the ISO develop and issue an RFP to obtain a methodology and analytical tools for evaluating the economic justification of multi-million dollar transmission investments. The RFP process is currently underway. Under the schedule presented in their Joint Testimony, the final report on an economic methodology will be available at the end of March 2002.

The ISO expects that the economic analysis of transmission projects, once a methodology is developed, would be used to supplement its annual Grid Coordinated Planning Process, which looks at system reliability needs. The ISO intends to apply the methodology to major complex projects with regional significance, including the significant (primarily 500 kV) lines needed to access and utilize Southwest generation.[10]

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[9] Exh. 1, p. 29.

[10] RT at 224, 226, Exh. 1, p. 28.

7. ISO Transmission Planning, Approval, and Cost Allocation

At the request of the ALJ, ISO Witness Miller clarified the process by which transmission projects are reviewed and approved by the ISO, and the ISO's cost allocation policies.

The ISO conducts an annual transmission planning process, referred to as the ISO Grid Coordinated Planning Process. This is a four-part process. Each of the three major transmission owners (PG&E, SDG&E, and SCE) develops its own transmission expansion plan, with the process open to stakeholders. Although ISO participates as a stakeholder in the transmission owners' separate planning processes, it also conducts an independent control area wide assessment and five-year expansion plan. The planning process culminates in an overall transmission plan for the ISO grid, comprised of the four components. At the end of the calendar year, or shortly thereafter, the ISO approves specific transmission projects identified in the plan.

There is also a planning process for generators, whereby the ISO can approve interconnections on a faster timeframe throughout the year. In addition, transmission projects can come before the ISO as part of a special study or stakeholder process. For example, Witness Miller testified that the ISO would expect to consider the reliability need for a major Southwest intertie either as part of the annual studies conducted for the Grid Coordinated Planning Process, or in a separate study.[11]

Projects under $20 million are approved by ISO management, i.e., the Regional Transmission Manager in the Grid Planning Department in

[11] RT at 205-206.

consultation with ISO officers, as needed. Projects over $20 million must go to the ISO Board of Governors (Board) for approval. Since the ISO has been established, less than 10 out of almost 200 transmission projects approved by the ISO have required Board approval. Those requiring Board approval have included Valley Rainbow and reinforcements in Northeast San Jose, among others.

After obtaining ISO approval, the transmission owners file CPCN applications, as required, before this Commission. They also file their transmission expenses for rate recovery with Federal Energy Regulatory Commission.

In terms of cost allocation, the ISO tariff states that where there is a project recommended for economic reasons and the beneficiaries can be identified, there should be an equitable distribution of the costs among the project beneficiaries. The tariff does not describe a specific process for identifying the beneficiaries or allocating the costs among them. However, ISO Tariff 13 provides for an Alternative Dispute Resolution process in the event of a disagreement over this and other issues.[12] In actual practice, the ISO has never had to address cost allocation issues for projects recommended for economic reasons. All of the transmission projects that have come before the ISO since its inception in 1997 have been based on basic reliability needs, where the costs are rolled into utility rates.[13]

In discussing what the ISO's role might be in the future with respect to economic projects, Witness Miller expressed his view that the ISO would

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[12] See Exhs. 29 and 30.

[13] RT at 181-182, 192-208, 290-293.

"facilitate a resolution" rather than make a determination on how the costs of economic transmission projects should be allocated between California ratepayers and project developers.[14] He also expressed some doubt that the ISO had the legal authority to hold generators to any cost allocation that they were unwilling to bear.[15]

8. Positions of the Parties

Joint Parties conclude from the results of the scenario analysis that the need for added transfer capability from Southern California to the Southwest for reliability is unlikely before 2008. However, they believe that new transmission projects may be justified on economic grounds. They recommend that further analysis be done on the economic need for additional transfer capability through the RFP process described above.

Coral Power argues that the Joint Study ignores a critical need for transmission upgrades along the SDG&E / Mexico transmission intertie ("Path 45"). Path 45 is the transmission path between Mexico and the Southern California system, and is jointly owned by SDG&E and CFE. It is comprised of a western leg (Tijuana-Miguel) and an eastern leg (La Rosita-Imperial Valley). Coral Power argues that Path 45's current import capacity of 408 MW will not be sufficient to accommodate CFE's planned exports of up to 800 MW, plus additional output from generation projects being developed in Northern Mexico and the US-Mexico border area of SDG&E's service territory.

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[14] RT at 200.

[15] RT at 201.

In Coral Power's view, upgrades on SDG&E's southern in-state transmission system are also critically important in order to enable new generation capacity to reliably supply Southern California load. Specifically, Coral Power contends that up to 4,120 MW of new capacity will be developed and much of it will be located on the east side of Miguel substation. In order to make this new generation readily available to Southern California, Coral argues that an upgrade to SDG&E's 230 kV Mission-Miguel line (west of Miguel) is necessary.

SSRC submitted testimony on the implications of the Joint Testimony for SDG&E's proposed Valley-Rainbow 500 kV transmission line (A.01-03-036). In SSRC's view, the matrix analysis does not provide any evidence that an in-state link such as the Valley-Rainbow 500 kV line, or its electrical equivalent, is needed for reliability or other reasons in the study period of 2001-2011.

9. Discussion

The purpose of the summer hearings, as directed by the ALJ, was to evaluate the system benefits and costs of adding transmission capability to the Southwest under multiple load and generation scenarios. For reasons described above, the Joint Parties only presented scenario analysis related to the need for transmission from a reliability perspective, i.e., the need to import power when in-state generation is insufficient to meet "physical" loads. We discuss that analysis below. At this time, we have no information on the record as to whether or when it would be advantageous to build new transmission to the Southwest from an economic perspective, i.e., to make less expensive power available to ratepayers.

The record in this proceeding shows that the ISO has never assessed this type of economic need for transmission projects since its inception in 1997. The last time the utilities came before the Commission with a transmission project designed to provide economic benefits in the form of cost savings from less expensive out-of-state energy production was in 1988, with SCE's amended application to construct Devers-PaloVerde No. 2.[16] One of the issues we consider today is how best to obtain and evaluate information on the economic impacts of new transmission projects in the future. As discussed further below, we believe that this information is critical to California ratepayers and should be evaluated in an open, public forum, with an evidentiary record.

We agree with the Joint Parties' conclusion that at least for reliability purposes, California most likely will not need additional Southwest transmission capacity before 2008. However, we have strong reservations about the analysis by which the Joint Parties reach that conclusion. Below, we explain our reservations, and what we did in this proceeding to satisfy them, to ensure that the present conclusions have a sound basis and to guide future reliability analysis.

9.1 Conclusions from Reliability Analysis

The credibility of the Joint Parties' conclusions with respect to the need for new Southwest transmission capacity is dependent upon both the credibility of the model and information used in the reliability analysis. We have reservations about both.

The first reservation concerns the use of the Joint Parties' matrix model, which is a simplified planning tool compared to the power flow model. The validation ('benchmarking') of the matrix model against the power flow model depends on the derating method used by the ISO, since without derating the

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[16] See D.88-12-030.

matrix model forecasts transmission need several years later than the power flow model. As we discuss below, the assumptions supporting the derating method are themselves open to question; in addition, the derating method was not applied consistently in the analysis. The second reservation concerns information used in the model. In some respects, key assumptions appeared to be out-of-date, and the Joint Parties did not thoroughly assess which sets of assumptions ("scenarios") are deemed more or less likely.

Consequently, we had additional model runs performed during the proceeding using updated assumptions and consistent use of the derating method relied upon for benchmarking. We then examined all of the results from the perspective of which scenarios seemed likeliest to occur. This examination convinces us that our conclusion about transmission reliability needs is valid for the 2001-2011 planning period. In the following discussion, we deal first with derating issues and then with information issues, in each cases detailing the adjustments we directed.

With respect to the validity of the matrix model, we note that the ISO and utilities have never used the matrix modeling approach presented in this proceeding to evaluate the need for new transmission.[17] To test its validity, Joint Parties compared the results of one case (Very Low Internal Generation/Base Load) under the Planning Scenario against the results of the detailed power flow model used in the Southern CA Study.

The results of the matrix model and the Southern CA Study are the same for that case *only* if transmission capability is derated in the matrix model, as described in Section 4.8 above. Hence, the validity of the matrix model as a

[17] RT at 170.

reasonable simplification of a power flow model for assessing reliability needs is called into question if the derating methodology is inaccurate or applied inappropriately. ISO Witness Le testified that up to a 500 MW excess of new load over new internal generation could be addressed by relatively minor internal "fixes," but above that amount, a derate would probably have to be applied on a one-to-one basis without proper reactive voltage support.[18] However, upon further questioning, ISO Witness Le acknowledged that this one-to-one assumption would have to be confirmed with power flow studies.[19]

In addition, Witness Le testified that derating might not be required at all if there is sufficient reactive voltage support on the system.[20] Moreover, if projects to provide additional reactive voltage support were installed, Witness Le stated that the one-to-one ratio used in the formula would not hold.[21] In fact, because reactive voltage support increased substantially since last year (due to the installation of shunt capacitors and other devices), the Western Systems Coordinating Council (WSCC) recently increased the transfer capability rating for Southern California, even while the gap between new load and new generation is expected to widen.[22] While acknowledging that reactive voltage support is a factor in determining whether transmission transfer capability should be derated, Witness Le stated that he did not have a formula to capture

[18] RT at 316-317, 338.

[19] RT at 339.

[20] RT at 317.

[21] RT at 339.

[22] RT at 213-219, 314-321.

that relationship.[23] We also note that the derating formula is not applied to models used to derive resource needs arithmetically in other ISO planning forums, as indicated in the most recent Study Plan for SCE's Grid Expansion Study.[24]

If the one-to-one derate ratio is inaccurate, or should not be applied at all, the matrix model results will not match the Southern CA Study for the benchmarked case. As indicated in Table 1, if the benchmarked case is run without derating transmission capability, then additional transmission is not needed in 2008 (the year that need is shown under the more detailed Southern CA Study), but rather sometime after 2011. This represents a very large potential "bias" in the matrix model results if derating is inappropriately applied. In other words, we must consider the possibility that the matrix model will *underestimate* the need for new transmission by approximately 2-3 years.

To the extent that we are comfortable with derating transmission capability along the lines described by the modeling witness, we can accept the results of the matrix model as a reasonable simplification of more complicated reliability modeling efforts. However, as ISO acknowledges, the derating formula was not applied consistently in the scenario analyses presented on the record, even in the very low generation cases.[25] In its brief, the ISO also recognizes that capacity retired should be deducted from new internal

[23] RT at 316, 326.

[24] Exhs. 28 (Table 3A) and 32; RT at 314-315, 339-342.

[25] Instead of calculating a different derate formula for the baseload, baseload plus 10% and baseload plus 20% runs, Witness Le applied the formula derived for the baseload run to all three. RT at 322, 332-333. ISO Opening Brief, pp. 11-12.

generation in the formula for derating transfer capability.[26] We have recalculated the matrix model results using the derate formula applied consistently across all cases, and factoring retirements into the formula.

In addition, we have updated two assumptions regarding transmission transfer capacity. First, we have increased the Path 45 transfer capacity of 408 MW to 800 MW, effective in 2002, consistent with the record.[27] In addition, as noted above, the Operational Transfer Capability Committee of the WSCC recently approved an increase in the transfer capability of Southern California import transmission from 13,200 MW to 14,300 MW (or 8.3%) due to the installation of new reactive voltage support. As Witness Le acknowledged during hearings, had he been aware of the WSCC ruling when he prepared the matrix, he would have applied the derating to the higher level of transfer capacity throughout the planning period.[28]

The results of these changes are presented in Tables 3 and 4 appended to this decision. As indicated in these tables, the net effect of increasing the import capability and applying the derate methodology to all cases defers the need for new transmission in most cases, relative to the results presented in Tables 1 and 2. This is because the increase in transmission capability (which will delay need) is in full effect early in the planning period, whereas the derate (which will

[26] ISO Opening Brief, p. 17.

[27] RT at 114-115.

[28] ISO Opening Brief, p. 12, 17. RT at 213-219, 314-321. As noted in Section 4.8 above, the total amount of import capability is adjusted to reflect the entitlements for ISO controlled grid and other commitments. Thus the 13,200 MW translates into 7,319 MW of available import capability in the model for the purpose of assessing system reliability.

accelerate need) is only in full effect at the end of the period, when load growth is at its peak.

In evaluating these results, we must consider which sets of assumptions capture the most likely range of possible outcomes for the future. The ISO characterizes the Joint Parties' "Planning Scenario" (Scenario 1) as representing the more plausible set of assumptions regarding outages and retirements, and Scenarios 2 or 5 as "unlikely."[29] However, the evidence in the record presented by the CEC witness for the Joint Parties indicates that Scenario 2 assumptions for outages are more credible. As CEC Witness Vidaver testified, historical data on outages indicates that a one or two day each summer outage level in Southern California would be on the order of approximately 3000 MWs, rather than the 1150 MW assumed in Scenario 1.[30]

We are also not persuaded that the "no retirements" assumption used in Scenario 1 is more likely than one where some generation facilities are retired in the future, based upon the inefficiency of the units involved. CEC Witness Vidaver testified that all of the units retired in Scenarios 2 and 5 have very high heat rates, in the range of 12,000 to 20,000 Btu per kWh, and that current prices are not enough to sustain these plants.[31] We find it more plausible to assume that these highly inefficient units will retire between now and 2011, rather than to assume no retirements.

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[29] RT at 191.

[30] RT at 273-280.

[31] RT at 284, 287.

With respect to the various load forecast assumptions, we agree with Joint Parties that the base load plus 10% or 20% load cases are unlikely.[32] In fact, the record in this proceeding supports a conclusion that somewhere between the "base load" and "base load minus 10%" represents the most plausible range of load projections. SCE Witness Canning testified that, by early May, conservation efforts appeared to be stabilizing at about 5% below the October 2000 forecast of base load levels.[33] SDG&E Witness Jack testified that SDG&E's forecast of load is somewhat higher than CEC's projections used in the matrix model, so that accounting for more extensive conservation and other factors, would not bring it to 10% below the base load forecast, in his opinion.[34] CEC Witness Rohrer testified that although there had been reductions in demand on the order of almost ten percent, those occurred in April or May before the summer air conditioning season began. In his view, a 5% reduction below CEC's baseload projections would probably be more sustainable when customers had to choose between saving energy and "sweat[ing] in their houses."[35]

Based on the record in this proceeding, approximately 1950 MW of new generation projects are under construction that will be available to Southern California (including 720 MW at High Desert), and more than 3000 MW of additional capacity has been approved and is in various stages of financing.[36]

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[32] RT at 191.

[33] Exh. 17, p. 2.

[34] RT at 19-21.

[35] RT at 23.

[36] Exh. 10, Table 1.

We therefore agree with Joint Parties that the "very low" generation case, where only 720 MW of new generation is assumed to materialize, is highly unlikely.[37] However, it is much more difficult to assess the likelihood of "low" (approximately 5,500 MW) to "maximum" (20,500 MW) new in-state generation actually coming on line, given the information available at this time. As SDG&E and SCE witnesses testified, the utilities have never before had generators of this magnitude wanting to build in California. This is a new phenomenon that started over the past year. Therefore, they do not have any history on what would be the likelihood that proposed projects will actually be built.[38]

Similarly, it is difficult to assess the likelihood of how many resources will materialize for export from Mexico to California. There have been no exports from Mexico to Southern California in the past, and construction and financing on these new projects have not been completed,[39] nor have contracts or commitments for power delivery to Southern California been finalized in all cases.[40] SDG&E projects a maximum of 2550 MW of export from Mexico by 2005, based on its Mexico interconnection queue. Coral Power estimates that there will be an additional 1300 MW available from 1) a 500 MW Rosarita Project planned for construction in Mexico and 2) 800 MW of exports during the winter period by CFE.[41] Hence, the record presents a range between approximately 500 MW

[37] RT at 191.

[38] RT at 165-167.

[39] RT at 65, 113, 152-153.

[40] RT at 136-142.

[41] Exh. 15; RT at 127-128, 133-134, 154-155.

(medium) and 3,850 MW (maximum) potential of exports from Mexico during the planning period.[42] As in the case of in-state new generation, we do not have sufficient information to assign the likelihood of projects materializing within this broad range.

In terms of the assumptions concerning potential exports from Arizona/Nevada, we note that there was apparent miscommunication between the CEC witness who prepared the CEC project status list and the ISO matrix modeling witness who used this list to derive inputs for the matrix model. ISO Witness Le testified that he thought he was receiving figures relating to projects only under CEC status 1-3 (projects under construction, approved or under CEC review), which are generally used in CEC load and resource assessments.[43] As described in Section 4.4 above, 50% of the project totals were used for the maximum case and 20% for the medium case runs. Instead, Le applied these percentages to the resources listed under CEC status levels 1-5, which include projects identified in press releases, or just starting the application process with CEC. In fact, projects listed under CEC status levels 1-5 include approximately 10,000 more MW for Arizona and Nevada than levels 1-3.[44] Because of this miscommunication, we consider it unlikely that the maximum case scenarios for external resources available from Arizona and Nevada will materialize.

The results of the matrix scenario analysis, when derating is consistently applied and transfer capability is updated, indicates no need for new

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[42] This range does not include the Otay Mesa project discussed in Coral Power's testimony, which is already included in SDG&E's in-state new generation queue.

[43] RT at 121-122, 124.

[44] RT at 121-123.

transmission to the Southwest until 2009 or beyond in all cases except those run under the most "unlikely" assumptions: 1) very low new internal generation (720 MW) and 2) low or medium internal generation with a 10% or 20% increase in base load demand. In fact, the only two cases in which need is indicated before 2011 in scenarios with low, medium or maximum internal generation is the "low generation" scenario with a 1) 10% increase in base load demand, assuming no retirements after 2004, and 2) base load demand assuming post-2004 retirements. (See Table 4.) Hence, the preponderance of cases run with the updated transfer capability assumptions indicate that new transmission for reliability reasons will not be needed until 2011 or later. These results assuage our concerns over the possibility that the matrix model contains a bias towards underestimating the need for new transmission. As discussed above, if the ISO's derating concept is questionable and the matrix model actually underestimates need by 2-3 years based on the benchmark run, the need for new transmission still does not surface before 2008, under all but relatively unlikely combinations of load and internal generation assumptions.

We will monitor the reliability modeling efforts conducted through the ISO's Grid Coordinated Planning Process in order to update and confirm these results with the detailed power flow studies conducted during that process. To this end, we direct Energy Division to report to us on an ongoing basis if the power flow studies indicate a need for reliability purposes earlier than 2008. This report should take the form of a letter to the Assigned Commissioner and ALJ, with service on all parties in this proceeding, or its successor.

The results of the reliability analysis in this proceeding indicate that we have a sufficient window of time to further update planning assumptions and consider the need for new transmission to the Southwest from an economic perspective. However, we do not believe that decisions concerning the economic need for major transmission projects, which could cost ratepayers over a billion dollars, should be left to the discretion of the ISO management personnel or Board, given that the ISO does not have the mandate or statutory authority to protect ratepayers' interests, and lacks an open, evidentiary process to scrutinize the methodologies and assumptions used to reach such decisions. While we appreciate the ISO's efforts to facilitate a resolution of the economic need issues through an RFP process, we believe that the public interest is best served by evaluating the economic need for new transmission projects, and the appropriate allocation of costs among beneficiaries, in this proceeding-- where we can ensure that a public record is fully developed. To that end, we direct SCE, SDG&E, and PG&E to jointly file the results of the ISO / stakeholder RFP process within 15 days from the date that the consultant's final report is completed. The assigned ALJ will hold a PHC as soon as practicable thereafter to schedule evidentiary hearings on the economic need for new transmission to the Southwest.

9.2 Other Issues

With regard to Coral Power's testimony concerning needed in-state transmission upgrades, we have recently scheduled a separate set of evidentiary hearings on the net economic benefits to ratepayers of relieving two potential in-state transmission constraints in Southern California, including alternatives to address potential congestion west of Miguel.[45] On the issue of upgrades to Path 45, we note that SDG&E is already moving ahead with adding a second circuit to the La Rosita-Imperial Valley component of Path 45, which will increase the capacity of that path from 408 to approximately 800 MW this fall.

[45] See Administrative Law Judge's Ruling dated July 19, 2001.

There are already general discussions underway between SDG&E and CFE to consider additional upgrades to Path 45.[46] We direct SDG&E to submit information on the status of those discussions and any upgrade proposals that would involve additional ratepayer funding in the monthly status reports ordered by D.01-03-077.[47] To the extent that significant ratepayer funding is involved to further upgrade Path 45, we may include this issue in the evidentiary hearings on economic need for new transmission to the Southwest. However, if private developers or the CFE fund the additional upgrades, then we will not need to review the issue further in this proceeding.

Finally, with respect to SSRC's position in this proceeding, we concur that no conclusions can be made from the record in this proceeding regarding the adequacy of the in-state transmission grid in Southern California.

10. Comments on Proposed Decision

The proposed decision of ALJ Gottstein was mailed to the parties in accordance with Section 311(d) of the Public Utilities Code and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on _____________ and reply comments were filed on _______________.

Findings of Fact

1. The modeling approach used in this proceeding to establish the reliability need for new transmission capability to the Southwest has never been used before by either the utilities or the ISO. The matrix model used in this

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[46] RT at 114-115, 148-149.

[47] D.01-03-077, Ordering Paragraph 2.

proceeding was benchmarked against the results of a Southern California power flow study, using one set of similar input assumptions.

2. The results of the matrix model are the same as those of the Southern California power flow study only if transmission capability is derated in the matrix model.

3. The one-to-one derating assumption used by the ISO in benchmarking the model has not been confirmed with power flow studies.

4. The derating formula was not applied consistently in the scenario analyses presented on the record. In addition, the formula does not deduct capacity retirements when calculating the gap between in-state generation resources and loads or the resulting derate of transfer capability.

5. The record indicates that derating would not be needed on a one-to-one basis, or perhaps not even at all, if sufficient additional reactive voltage support is installed. However, the derate formula used by the ISO does not factor in any relationship between reactive voltage support and required reduction in transfer capability.

6. If the one-to-one derate ratio is inaccurate, or should not be applied at all, the matrix model results will not match the Southern California study for the benchmarked case and will underestimate the need for new transmission by approximately 2-3 years.

7. Based on the record, the transfer capability of existing transmission interties is higher than the input assumptions used in the matrix model. Path 45 transfer capacity will be increased from 408 MW to 800 MW, effective in 2002. The transfer capability of Southern California import transmission has been increased from 13,200 MW to 14,300 MW due to the installation of new reactive voltage support.

8. The outage and retirements assumptions used for Scenarios 2, 4, and 5 are more consistent with the evidentiary record than those assumed under the Joint Parties' Planning Scenario.

9. Projections of load between base load and base load minus 10% assumptions are consistent with the record concerning future demand and conservation efforts. Load projections at 10%-20% above base load projections appear highly unlikely.

10. Based on the number of new generation projects under construction and the number that have already received financing for Southern California, the "very low" new internal generation case (720 MW) appears highly unlikely.

11. Because utilities have never before had a large number of generators wanting to build in California, it is difficult at this time to assess the likelihood of the "low" to "maximum" (5,500 MW to 20,500 MW) of new in-state generation coming on line.

12. Assessing the likelihood of projects coming on line for export from Mexico is difficult at this time because: 1) there have been no exports from Mexico to Southern California in the past; 2) construction and financing on new projects requesting interconnection studies have not been completed; 3) contracts and commitments for power projects have not been finalized in all cases.

13. The assumptions for external resources available from Arizona and Nevada are inflated because they are based on a resource potential estimate that is approximately 10,000 MW larger than the amounts generally used in CEC load and resource assessments.

14. Reruning the matrix model with updated assumptions on transfer capability and with the derating formula applied consistently (and incorporating retirements into the formula), yields the following results:

- No need for new transmission to the Southwest until 2009 or beyond in all cases except those run under 1) very low new internal generation (720 MW) and 2) low or medium internal generation with a 10%-20% increase in base load demand.
- The only two cases in which need is indicated before 2011 in scenarios with other than the "very low" internal generation assumptions is the "low" generation scenario with 1) a 10% increase in base load assuming no post-2004 retirements and 2) base load demand assuming post-2004 retirements.
- Accounting for the potential 2-3 year bias in the matrix model based on the benchmark run, the need for new transmission does not surface before 2008, under all but relatively unlikely combinations of load and internal generation assumptions.

15. The Joint Parties did not present an economic analysis of additional Southwest transfer capability on the record, but intend to pursue an RFP process initiated by the ISO to develop a joint methodology for such an analysis.

16. The Joint Parties presented preliminary cost estimates for transmission upgrades to the Southwest. The total estimates ranged between three-quarters billion to three and three-quarters billion dollars, depending upon the route and ultimate cost of transmission line per line.

17. Transmission owners, ISO staff, and interested stakeholders participate in the ISO's annual transmission planning process to identify projects needed for system reliability purposes. At the completion of this process, transmission projects under $20 million are approved by ISO management, i.e., the Regional Transmission Manager in the Grid Planning Department in consultation with ISO officers, as needed. Projects over $20 million are approved by the ISO Board. The ISO has never assessed the economic need for transmission projects since its inception in 1997. Since the ISO has been established, all of the projects approved (over 200) have involved upgrades to address reliability requirements. Less than 10 of those projects have required ISO Board approval.

18. The ISO does not conduct evidentiary proceedings to scrutinize the assumptions or methods utilized in its transmission planning process.

19. Based on the record in this proceeding, we find that new transmission to the Southwest (including Mexico) is not likely to be needed for reliability purposes before 2008. Our conclusions take account of recent updates to transmission transfer capability identified on the record, as well as potential bias in the model utilized by the Joint Parties.

20. The Commission should monitor the reliability efforts conducted through the ISO's Grid Coordinated Planning Process in order to update and confirm these results with the detailed power flow studies conducted during that process. As discussed in this decision, Energy Division should report to the Assigned Commissioner and ALJ if the power flow studies indicate a need for new Southwest transfer capability earlier than 2008.

21. The issues raised by Coral Power in this proceeding regarding the need to reduce congestion west of Miguel should be addressed in the separate set of evidentiary hearings scheduled this fall.

22. To the extent that significant ratepayer funding is involved to further upgrade Path 45, this issue may be included in the evidentiary hearings on the economic need for new transmission to the Southwest.

23. No findings can be made from this record regarding the adequacy of the in-state transmission grid in the Southern California region.

Conclusions of Law

1. Decisions concerning the economic need of major transmission projects, as well as the allocation of costs among ratepayers and other project beneficiaries, should not be left to the discretion of ISO management personnel or Board. Instead, this assessment should be made at the Commission, which has both a

statutory mandate and authority to protect ratepayers' interests and an open evidentiary process to scrutinize the methodologies and assumptions used to reach such determinations.

2. In order to proceed with further evaluation of transmission upgrades to the Southwest as soon as possible, this order should be effective today.

INTERIM ORDER

IT IS ORDERED that:

1. Energy Division shall monitor the reliability modeling efforts conducted through the California Independent System Operator's (ISO) Grid Coordinated Planning Process or other planning processes in order to update and confirm the results of this proceeding on an ongoing basis. Specifically, Energy Division shall report by letter to the Assigned Commissioner and Administrative Law Judge (ALJ) if the power flow studies indicate a need for new transmission capacity to Arizona, Nevada, and Mexico for reliability purposes earlier than 2008. This report shall be filed and served in this proceeding.

2. Pacific Gas and Electric Company, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company shall jointly file the results of the ISO / stakeholder Request for Proposal process in this proceeding within 15 days from the date the consultant's final report is completed. Copies of the full report shall be served on Energy Division and the assigned ALJ. A notice of the availability of this report shall also be served in this proceeding. As soon as practicable thereafter, the assigned ALJ will hold a further prehearing conference to schedule evidentiary hearings on the economic need for new transmission to the Southwest.

3. SDG&E shall submit information on the status of discussions or actions to further upgrade Path 45 in its monthly transmission status reports.

This order is effective today.

Dated ____________________________, at San Francisco, California.

Table 1

SUMMARY OF RESULTS: SCENARIOS WITH NO RETIREMENTS AND ISO OUTAGE FIGURES

Case #	Description of Load and Internal Generation	Availability of External Generation Levels	Year That New Line Needed (2001-2011 Planning Period) * With Derate	Without Derate
J1.1, J1.2	Maximum internal generation	Maximum and medium	after 2011	N/A
J1.3, J1.4	Baseload, Baseload plus 10%			
J1.5, J1.6	Baseload plus 20%			
J3.1, J3.2	Baseload less 10%			
J3.3, J3.4	Baseload less 20%			
J3.5, J3.6	Average Load			
J2.1, J2.2	Medium internal generation	Maximum and medium	after 2011	N/A
J2.4, J2.5	Baseload, Baseload plus 10%			
J2.6, J4.1	Baseload less 10%, less 20%			
J4.2, J4.4	Average load			
J4.5, J4.6				
J5.1, J5.2	Low internal generation	Maximum and medium	after 2011	N/A
J5.4, J5.5	Baseload, Baseload plus 10%			
J5.6, J6.1	Baseload less 10%, less 20%			
J6.2, J6.4	Average load			
J6.5, J6.6				
J7.4, J7.5	Very low internal generation	Maximum and medium	after 2011	N/A
J7.6, J8.4	Baseload less 10%, less 20%			
J8.5, J8.6	Average load			
J2.3 &J4.3	Medium internal generation levels Base load plus 20%	Maximum and medium	2011	N/A
J5.3 & J6.3	Low internal generation levels Base load plus 20%	Maximum and medium	2009	N/A
J7.1 & J8.1	Very low internal generation levels Base load	Maximum and medium	2008	after 2011
J7.2 & J8.2	Very low internal generation levels Base load plus 10%	Maximum and medium	2005	2008
J7.3 & J8.3	Very low internal generation levels Base load plus 20%	Maximum and medium	2001	2001

NOTES:

NA= "not applicable". Derating was only done for the baseload, baseload plus 10% and baseload plus 20% load runs under the "very low internal generation" cases.

* For some or all of the years, there may be insufficient external resources for import to meet all of the load demand within California.

Table 2

SUMMARY OF RESULTS: SCENARIOS WITH RETIREMENTS AND CEC OUTAGE FIGURES

Case #	Description of Load and Internal Generation	Availability of External Generation Levels	Year That New Line Needed (2001-2011 Planning Period) * With Derate	Without Derate	With Post-2004 Retirements**
J1.1, J1.2 J1.3, J1.4 J1.5, J1.6 J3.1, J3.2 J3.3, J3.4 J3.5, J3.6	Maximum internal generation Baseload, Baseload plus 10% Baseload plus 20% Baseload less 10% Baseload less 20% Average Load	Maximum and medium	after 2011	N/A	After 2011
J2.1, J2.4 J2.5, J2.6 J4.1, J4.4 J4.5, J4.6	Medium internal generation Baseload Baseload less 10%, less 20% Average load	Maximum and medium	after 2011	N/A	After 2001
J5.1, J5.4 J5.5, J5.6 J6.1, J6.4 J6.5, J6.6	Low internal generation Baseload Baseload less 10%, less 20% Average load	Maximum and medium	after 2011	N/A	After 2011
J7.5, J7.6 J8.5, J8.6	Very low internal generation Baseload less 20% Average load	Maximum and medium	after 2011	N/A	After 2011
J2.2 & J4.2	Medium internal generation levels Base load plus 10%	Maximum and medium	2010	N/A	2008
J2.3 & J4.3	Medium internal generation levels Base load plus 20%	Maximum and medium	2006	N/A	2005
J5.2 & J6.2	Low internal generation levels Base load plus 10%	Maximum and medium	2008	N/A	2007
J5.3 & J6.3	Low internal generation levels Base load plus 20%	Maximum and medium	2004	N/A	2004
J7.1 & J8.1	Very low internal generation levels Base load case	Maximum and medium	2004	2006	2004
J7.2	Very low internal generation levels Base load plus 10%	Maximum	2001	2002	2001
J7.3	Very low internal generation levels Base load plus 20%	Medium	2001	2001	2001
J7.4 & J8.4	Very low internal generation levels Base load less 10%	Maximum and medium	2011	N/A	2008

J8.2	Very low internal generation levels Base load plus 10%	Medium	2001	2002	2001
J8.3	Very low internal generation levels Base load plus 20% more	Medium	2001	2001	2001

NOTES:

NA= "not applicable". Derating was only done for the baseload, baseload plus 10% and baseload plus 20% load runs under the "very low internal generation" cases.

* For some or all of the years, there may be insufficient external resources for import to meet all of the load demand within California.

** Scenario with Post-2004 Retirements includes derating.

Table 3

SUMMARY OF RESULTS: SCENARIOS WITH NO RETIREMENTS AND ISO OUTAGE FIGURES

WITH UPDATED TRANSFER CAPABILITY AND DERATE CONSISTENTLY APPLIED

Case #	Description of Load and Internal Generation	Availability of External Generation Levels	Year That New Line Needed (2001-2011 Planning Period) *	
			With Derate	Without Derate
J1.1, J1.2 J1.3, J1.4 J1.5, J1.6 J3.1, J3.2 J3.3, J3.4 J3.5, J3.6	Maximum internal generation Baseload, Baseload plus 10% Baseload plus 20% Baseload less 10% Baseload less 20% Average Load	Maximum and medium	after 2011	after 2011
J2.1, J2.2 J2.4, J2.5 J2.6, J4.1 J4.2, J4.4 J4.5, J4.6	Medium internal generation Baseload, Baseload plus 10% Baseload less 10%, less 20% Average load	Maximum and medium	after 2011	after 2011
J5.1, J5.2 J5.4, J5.5 J5.6, J6.1 J6.2, J6.4 J6.5, J6.6	Low internal generation Baseload, Baseload plus 10% Baseload less 10%, less 20% Average load	Maximum and medium	after 2011	after 2011
J7.4, J7.5 J7.6, J8.4 J8.5, J8.6	Very low internal generation Baseload less 10%, less 20% Average load	Maximum and medium	after 2011	after 2011
J2.3 &J4.3	Medium internal generation levels Base load plus 20%	Maximum and medium	after 2011	after 2011
J5.3 & J6.3	Low internal generation levels Base load plus 20%	Maximum and medium	2011	2011
J7.1 & J8.1	Very low internal generation levels Base load	Maximum and medium	2010	after 2011
J7.2 & J8.2	Very low internal generation levels Base load plus 10%	Maximum and medium	2007	2009
J7.3 & J8.3	Very low internal generation levels Base load plus 20%	Maximum and medium	2004	2004

NOTES:
NA= "not applicable".

* For some or all of the years, there may be insufficient external resources for import to meet all of the load demand within California.

Table 4

SUMMARY OF RESULTS: SCENARIOS WITH RETIREMENTS AND CEC OUTAGE FIGURES WITH UPDATED TRANSFER CAPABILITY AND DERATE CONSISTENTLY APPLIED

Case #	Description of Load and Internal Generation	Availability of External Generation Levels	Year That New Line Needed (2001-2011 Planning Period) * With Derate	Without Derate	With Post-2004 Retirements**
J1.1, J1.2 J1.3, J1.4 J1.5, J1.6 J3.1, J3.2 J3.3, J3.4 J3.5, J3.6	Maximum internal generation Baseload, Baseload plus 10% Baseload plus 20% Baseload less 10% Baseload less 20% Average Load	Maximum and medium	after 2011	after 2011	after 2011
J2.4, J2.5 J2.6, J4.4 J4.5, J4.6	Medium internal generation Baseload less 10%, less 20% Average load	Maximum and medium	after 2011	after 2011	after 2011
J5.4, J5.5 J5.6, J6.4 J6.5, J6.6	Low internal generation Baseload less 10%, less 20% Average load	Maximum and medium	after 2011	after 2011	after 2011
J2.1, J4.1	Medium internal generation Baseload	Maximum and medium	after 2011	after 2011	2011
J5.1, J6.1	Low internal generation Baseload	Maximum and medium	after 2011	after 2011	2009
J7.6, J8.6	Very low internal generation Average load	Maximum and medium	after 2011	after 2011	after 2011
J2.2 & J4.2	Medium internal generation levels Base load plus 10%	Maximum and medium	2011	after 2011	2008
J2.3 & J4.3	Medium internal generation levels Base load plus 20%	Maximum and medium	2007	2007	2006
J5.2 & J6.2	Low internal generation levels Base load plus 10%	Maximum and medium	2009	2009	2007
J5.3 & J6.3	Low internal generation levels Base load plus 20%	Maximum and medium	2005	2005	2005
J7.1 & J8.1	Very low internal generation levels Base load case	Maximum and medium	2004	2007	2004
J7.2	Very low internal generation levels Base load plus 10%	Maximum	2004	2004	2004

J7.3	Very low internal generation levels Base load plus 20%	Medium	2001	2001	2001
J7.4 & J8.4	Very low internal generation levels Base load less 10%	Maximum and medium	2007	after 2011	2006
J8.2	Very low internal generation levels Base load plus 10%	Medium	2004	2004	2001
J8.3	Very low internal generation levels Base load plus 20% more	Medium	2001	2001	2001
J7.5, J8.5	Very low internal generation Baseload less 20%	Maximum and medium	2011	after 2011	2007

NOTES:
NA= "not applicable".

* For some or all of the years, there may be insufficient external resources for import to meet all of the load demand within California.

Figure 1 –Summary of Planning Scenario 1

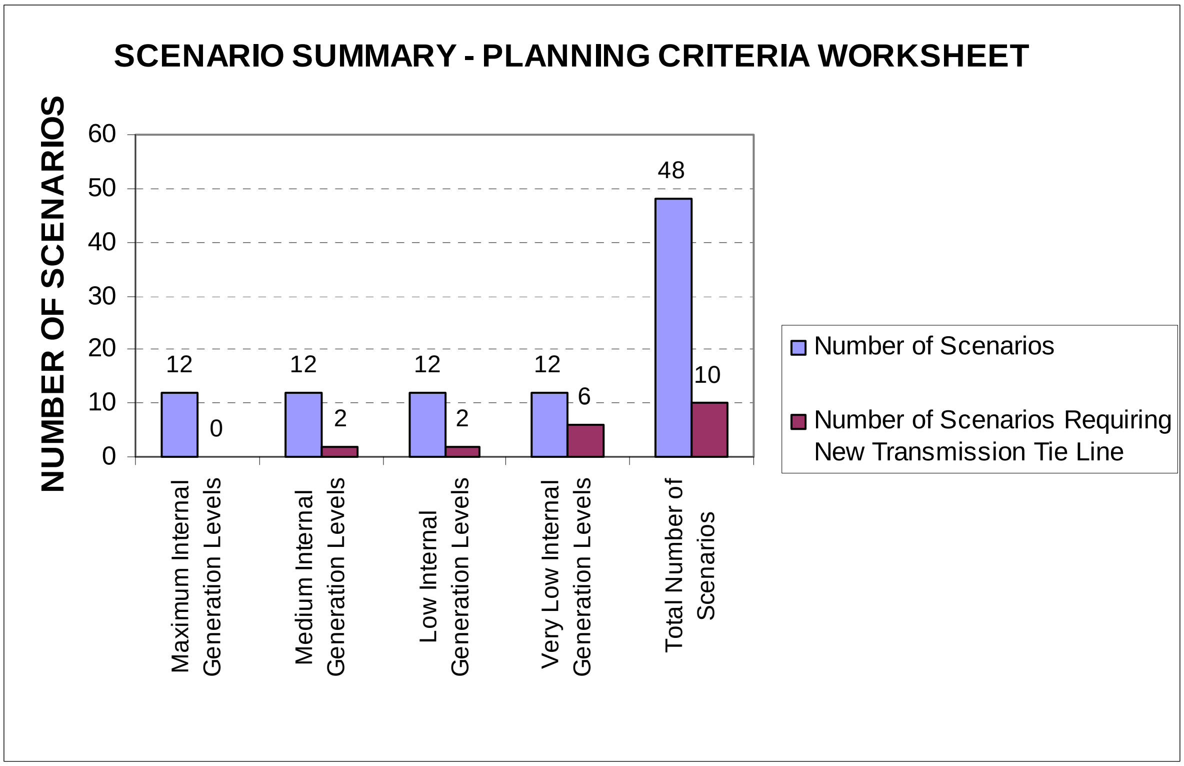
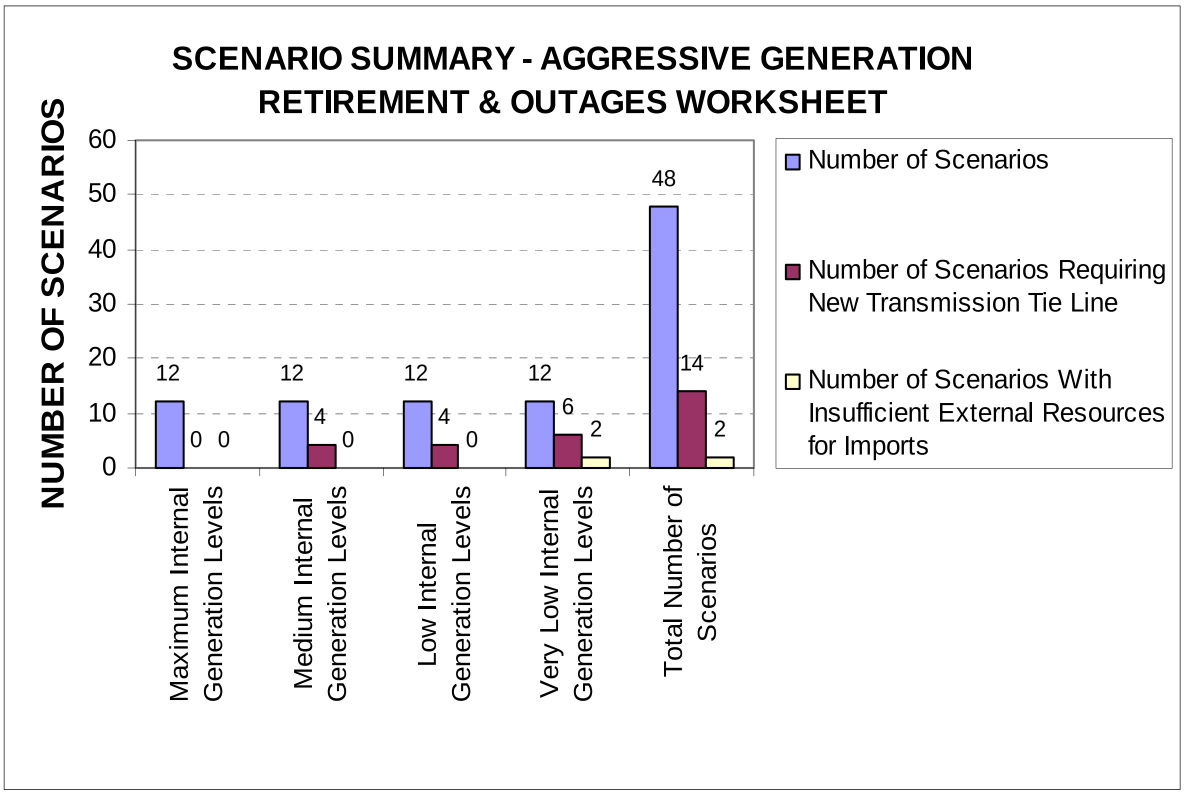


Figure 2 – Summary of Scenario 2 –

CEC's Alternate Retirement and Outages Assumptions



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(END OF ATTACHMENT 1)

ATTACHMENT 2
LIST OF ACRONYMS

AB	Assembly Bill
ALJ	Administrative Law Judge
Board	Board of Governors of the California Independent System Operator
Btu	British thermal units
CEC	California Energy Commission
CFE	Comision Federale de Electricidad
Coral Power	Coral Power L.L.C.
CPCN	Certificate of Public Convenience and Necessity
D.	Decision
Exh.	Exhibit
ISO	California Independent System Operator
Joint Parties	California Independent System Operator, California Energy Commission, Southern California Edison Company, and San Diego Gas & Electric Company
kWh	kilowatt hour
MW	megawatt
Path 45	SDG&E/Mexico transmission intertie
PG&E	Pacific Gas and Electric Company
PHC	Prehearing Conference
RFP	Request for Proposals
RT	Reporter's Transcript
SCE	Southern California Edison Company
Scenario 1	Joint Parties' Planning Scenario
SDG&E	San Diego Gas & Electric Company
Southwest	Arizona, Nevada or Mexico
SSRC	Save Southwest Riverside County
"the utilities"	San Diego Gas & Electric Company and Southern California Edison Company, collectively
WSCC	Western System Coordinating Council

(END OF ATTACHMENT 2)