Decision **ALTERNATE PROPOSED DECISION OF COMMISSIONER DUQUE** (Mailed 10/21/2002)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902-E) for a Certificate Of Public Convenience & Necessity Valley-Rainbow 500kV Inter-Connect Project.	Application 01-03-036 (Filed March 23, 2001)

OPINION ON THE NEED FOR ADDITIONAL TRANSMISSION CAPACITY TO SERVE THE SAN DIEGO GAS & ELECTRIC COMPANY SERVICE TERRITORY

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1. Summary[1]

Today's decision addresses San Diego Gas & Electric Company (SDG&E) request for a certificate of public convenience and necessity (CPCN) to construct a proposed 500 kilovolt (kV) transmission project and associated upgrades, called the Valley-Rainbow Project. The Commission concludes that SDG&E will not meet established reliability criteria under conservative supply and demand forecasts within the adopted five-year planning horizon. In reaching this conclusion, the Commission reviewed forecasts for existing and new generation in San Diego, the ability of SDG&E to rely on resources in northern Baja California, Mexico, the possibility for additional import capability due to transmission upgrades, and assumptions that impact the peak demand forecast. The evidence shows that SDG&E will continue to meet the reliability criteria until 2006, under the conservative planning assumptions utilized in today's analysis but after that point will no longer meet the reliability criteria. Therefore, the proposed project is needed for reliability purposes.

Although the proposed project is justified on the basis of reliability, the Commission also evaluated whether the proposed Valley-Rainbow Project would provide positive economic benefits to SDG&E ratepayers and California generally. The evidence shows that the proposed project is not cost-effective to ratepayers except under the extreme assumptions that six consecutive years of one-in-35 year drought conditions occur, all new generation available to serve California is located in San Diego or northern Baja California, Mexico, and a major transmission project (Path 15) is constructed in Northern California.

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

Because today's decision finds that there is a reliability need, the proceeding remains open to consider whether to grant a CPCN and explore alternatives to the proposed project developed in the Draft Environmental Impact Report / Draft Environmental Impact Statement.

2. Project Description

The Valley-Rainbow Project would provide an interconnection between SDG&E's existing 230 kV transmission system and Southern California Edison Company's (SCE) existing 500 kV transmission system. The proposed project is located in northern San Diego County and southwestern Riverside County. The proposed project consists of:

1) construction of a new 500 / 230 / 69 kV substation located in Rainbow in northern San Diego County;
2) construction of approximately 31 miles of 500 kV single-circuit overhead transmission line from SCE's existing Valley Substation to the proposed Rainbow substation; and
3) modification of the existing Valley Substation to accommodate the new 500 kV transmission line.

In addition, the proposed project would add an additional 230 kV circuit to the existing Talega-Escondido 230 kV transmission line, rebuild 7.7 miles of 69 kV transmission line between the existing Pala and Lilac Substations, and add voltage support systems to the existing Mission, Miguel, and Sycamore Canyon Substations.

We refer to this plan of service as the "proposed project" or "Valley-Rainbow Project" throughout this decision. When discussing the proposed 500 kV line between Valley Substation and the proposed Rainbow Substation, we refer to the "Valley-Rainbow 500 kV line."

3. Procedural Background

Application (A.) 01-03-036 was filed on March 23, 2001 and assigned to Commissioner Duque and Administrative Law Judge (ALJ) Cooke. In his August 13, 2001 Scoping Memo, Commissioner Duque designated ALJ Cooke to be the principal hearing officer for this proceeding.

Numerous parties filed protests or comments on SDG&E's application. ALJ Cooke and Commissioner Duque held a prehearing conference on June 21, 2001, as well as public participation hearings in the communities in the project area on June 19, 20, and 21, 2001. The Assigned Commissioner's Scoping Memo bifurcated the proceeding into two phases with the first phase to address the issue of whether the Valley-Rainbow Project is needed, and the second phase to address all other issues following the release of a Draft Environmental Impact Report / Environmental Impact Statement (DEIR / EIS).

SDG&E and the California Independent System Operator (ISO) served opening testimony on October 5, 2001. The Office of Ratepayer Advocates (ORA) served opening testimony on February 4, 2002. Save Southwest Riverside County, City of Temecula, and Pechanga Development Corporation (jointly SSRC) and Centex Homes (Centex) served opening testimony on March 15, 2002. SDG&E and the ISO served rebuttal testimony on April 12, 2002. A PHC was held on April 29, 2001 and parties presented opening statements at that time. SSRC, ISO, and ORA served surrebuttal testimony on May 6, 2002. Nine days of evidentiary hearings were held, beginning on May 6, 2002 and concluding on May 16, 2002. Parties presented closing arguments before Commissioner Duque and ALJ Cooke on August 20, 2002. No final oral argument was requested.

Opening briefs were filed by SDG&E, the ISO, ORA, SSRC, Centex, Greenpeace, and the Southern California Generation Coalition (SCGC). Reply briefs were filed by SDG&E, the ISO, ORA, SSRC, Centex, Greenpeace, and the Electric Generator Alliance (EGA). This phase was submitted on August 20, 2002 following closing argument.

4. Request

By this application, SDG&E seeks a CPCN to construct additional transmission capacity to provide an interconnection between SDG&E's existing 230 kV transmission system and SCE's existing 500 kV transmission system. In this phase of the proceeding, SDG&E seeks a finding that the Valley-Rainbow Project, or an alternative project that provides the same amount of new transmission capacity, is needed by 2005 to allow SDG&E to meet reliability criteria established by the Western Electricity Coordinating Council (WECC)[2] and the North American Electric Reliability Council (NERC). In the alternative, SDG&E seeks a finding that the Valley-Rainbow Project, or a similar project, should be authorized because of the economic benefits provided to California ratepayers.

5. Jurisdictional Issues

SDG&E and the ISO assert that the Commission should defer to the ISO's determination regarding the need for transmission projects like the Valley-Rainbow Project. The ISO argues that:

> "Transmission planning is an integral part of assuring transmission grid reliability. Public Utilities Code §345 explicitly notes that the CA ISO must ensure compliance with planning criteria as well as operating reserve criteria, making it clear that the CA ISO has

[2] WECC was previously called the Western Systems Coordinating Council (WSCC) and therefore may be referred to by the parties in testimony or briefs as WSCC.

> responsibility to provide for transmission planning. Moreover, without adequate facilities it is not possible to 'ensure efficient use and reliable operation of the transmission grid.' Thus, it would not be possible for the CA ISO to ensure compliance with planning criteria is it did not have a meaningful role in identifying the facilities that must be built to meet the standards, and it it's [sic] determinations of need are ignored in the siting process." (ISO Opening Brief at 57.)

SSRC and ORA disagree that deference to the ISO's determination of need is required under law. SSRC argues:

> "The Commission's obligation to determine whether a major transmission line is needed is set forth in State law and has remained unchanged throughout the recent period of energy restructuring legislation, during which the nascent ISO was established. Section 1001 of the Public Utilities Code provides that: 'No . . . electrical corporation . . . shall begin the construction of a . . . line, plant, or system, or of any extension thereof, without having first obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction.' Pub. Util. Code § 1001. This provision of law requires the Commission to determine whether proposed transmission projects are needed, and the Commission has considered CPCN applications and made need determinations pursuant to this provision since the provision's enactment and subsequent to the establishment of the ISO." (SSRC Reply Brief at 61-62.)

SSRC points out that the Commission found just last year that the "ISO has responsibility to ensure the reliability of the State's electrical system pursuant to Pub. Util. Code § 345. However ensuring reliability and deciding that a particular transmission project should be built are two separate issues." (D.01-01-029, 2001 Cal. PUC LEXIS 1000 at *229.) This decision echoes language in D.01-05-059, 2001 Cal. PUC LEXIS 413 at *27, which was also adopted in 2001.

Although we appreciate the ISO's efforts to evaluate this proposed project, we continue to disagree with the ISO's assertion that we must defer to its judgment about the need for transmission projects. Pub. Util. Code § 1001 places an ongoing responsibility on this Commission to evaluate the public convenience and necessity of proposed transmission projects, and therefore we independently assess the record developed in this proceeding to determine whether the Valley-Rainbow Project is needed on the basis of either reliability or economics.

6. Reliability Need

SSRC provides an excellent summary of how reliability need is determined:

> "In order to determine whether a given service area needs a transmission or generation upgrade project for reliability purposes, planners compare the reliability performance of the power system against applicable reliability criteria under prescribed outage contingencies. The North American Electric Reliability Council ("NERC") and the Western Electricity Coordinating Council ("WECC") have developed a number of reliability criteria designed to ensure that all transmission systems meet a uniform set of reliability standards. The NERC / WECC Reliability Criteria have been adopted by the ISO and are appropriately applied to the SDG&E service area. These criteria prescribe the contingencies under which performance is to be measured and specify the acceptable levels of performance. [Citation omitted.]
>
> The reliability criteria provide, among other things, that a utility such as SDG&E should be able to continue to serve its forecasted one-in-ten year peak demand for electricity, [footnote omitted] even when the largest in-area power plant is out of service and there is a simultaneous outage along the single most critical network transmission connection used to import power into the area. … This reliability criterion is commonly referred to as testing the N-1 / G-1 scenario because it looks at the overlapping outage of a utility's most critical transmission network element (N-1) and the most critical generator (G-1). …

> It has been undisputed among the parties to this proceeding that in SDG&E's service area, the 329 MW Encina Power Plant Unit 5 is currently the most significant in-area generator (G-1). An outage along the Southwest PowerLink ("SWPL") between the Imperial Valley Substation and the Miguel Substation is the utility's most critical transmission network element outage (N-1). As such, the N-1 / G-1 reliability criterion provides that SDG&E should be able to continue to serve its one-in-ten year peak load, even when the Encina Unit 5 (or an equivalent amount of local generating capacity) is off-line and the SWPL suffers a sudden outage between the Imperial Valley Substation and the Miguel Substation." (SSRC Opening Brief, pp. 30-32.)

SDG&E's primary argument is that we should approve the Valley-Rainbow Project because SDG&E will violate the N-1 / G-1 reliability criterion beginning in 2005 because it forecasts increasing customer demand and a shortage of in-basin generating resources.[3] The ISO supports SDG&E's position. Other parties argue that the generation forecasts SDG&E relies on are unduly conservative and the demand forecasts are unduly aggressive.

In essence, we must determine whether there is a reliability need under a reasonably foreseeable supply and demand forecast based on today's best information within an appropriate planning horizon. SDG&E and the ISO argue that a deficiency exists within the planning horizon; SSRC and ORA argue that no deficiency occurs within that horizon. SDG&E spends a fair amount of time in its briefs arguing that the Valley-Rainbow Project is the most effective project to

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[3] SDG&E appears to argue in its brief that the ISO is likely to change the relevant N-1 / G-1 reliability criteria to a more stringent criteria, for example N-1 / G-2. (See SDG&E Opening Brief at 15.) However, there is no evidence in the record that the ISO plans to pursue such a change, therefore we do not further address SDG&E's arguments on this point.

meet its identified capacity deficiency, for various reasons. However, in this phase of the proceeding, we are only attempting to determine whether a need for the project exists, not evaluate alternatives. If we find that a capacity deficiency exists within the planning horizon, then alternatives to SDG&E's proposed solution will be explored and evaluated to determine which alternative best meets the identified need. We explore the proper planning horizon and the forecasts in detail below.

6.1. What is the appropriate time horizon over which to assess the need for SDG&E's Proposed Project?

SDG&E and the ISO recommend that ten years is the proper planning horizon for major transmission projects like Valley-Rainbow. SDG&E argues that a ten-year period of time is needed for this type of project because of the lengthy licensing process. (SDG&E Opening Brief at 50.)

The ISO states:

> While there was disagreement about whether the Commission should make a decision on a project such as Valley-Rainbow now, most witnesses agreed that it is appropriate to look out [at] least ten years in planning the transmission system [citations omitted]. Most witnesses also agreed that from the time a determination is made to build a major transmission project, such as Valley-Rainbow, until the project is permitted and constructed can take five to six years. [citations omitted]. It is now the middle of 2002. Before a project such as Valley-Rainbow can be built, a further phase of Commission proceedings must take place, which is not scheduled to conclude until August 2003. [citations omitted.] This leaves only two to three years for a project to be completed after the final Commission decision - a feasible but not extended schedule if need materializes in 2006. (ISO Opening Brief at 45.)

SDG&E argues that SSRC's brief contradicts the recommendation of its witness who testified that all planning options "have to be considered in a ten-year horizon. (RT 1211:15-16.)

The ISO argues that "[a]n important challenge in the context of transmission planning is managing uncertainty." (ISO Reply Brief at 6.) The ISO supports taking into account both known information and uncertainty, and if appropriate, building milestones into CPCN decisions to help ensure that utility activities are phased to meet need as it develops. The ISO argues that dismissal of SDG&E's application "would be a risky and potentially wasteful response to uncertainty." (ISO Reply Brief at 6.) The ISO recognizes that substantial uncertainty exists regarding generation development and load growth beyond five years and this uncertainty becomes more severe further out in time.

The ISO believes:

> "Valley-Rainbow aptly illustrates why a five year planning horizon is inappropriate in the case of a larger facility…. [I]f SDG&E waited until there was more certainty about whether Otay Mesa will be built and the extent of retirements before filing a CPCN application, it would file too late to make a 2006 in-service date. Thus, a five year planning horizon does not adequately account for the fact that there will, in most cases, be uncertainty affecting the precise year of need for any major facility. Nonetheless to ensure that a major facility is in place when needed permitting of a major facility must commence five years before the earliest likely year of project need, and rejection of a CPCN application on the grounds that need might be delayed for a year or two would just result in the need to refile an application and relitigate need within a year or two of the rejection." (ISO Reply Brief at 7-8.)
>
> "The CA ISO recognizes of course that it is possible that Otay Mesa could be built in which case, if there are no retirements, need could be deferred to 2008-9. However, given market

> circumstances, and the condition of the generating fleet in San Diego, the CA ISO considers that it would be injudicious to reject SDG&E's application for a CPCN relying on a deferral of need to 2008-9. Moreover, as the CA ISO noted in its opening brief, even if need were to be deferred to 2008-9, in this case it makes sense to proceed to phase 2, since rejection of the application would just result in the need to relitigate need in a year and in the context of the new sources of uncertainty that will undoubtedly have developed in the intervening time period." (ISO Reply Brief at 9-10.)

The ISO would prefer that the Commission "grant the CPCN conditioned on a schedule that takes account of the deferred need date, the activities that must be undertaken by SDG&E to meet this date, and further events that could have a significant further impact on the year of need. The CPUC could require bi-yearly updates by SDG&E to monitor whether as circumstances develop the need for a project such as Valley-Rainbow is either accelerating or being further deferred, and adjust the schedule accordingly." (ISO Reply Brief at 10.) The ISO argues that without this type of approach San Diego will be condemned "to a on-going patchwork of short term transmission fixes to address new resource needs." (ISO Reply Brief at 10.)

In contrast to the ISO and SDG&E, SSRC asserts that "the appropriate planning horizon to apply in the 'need' phase of this proceeding is five years," that the "five-year period commenced when SDG&E filed its CPCN application and therefore runs from 2001 to 2006" and "to prevail with its CPCN application, SDG&E must establish that the project (or something like it) is needed for reliability beginning in the year 2006." (SSRC Opening Brief at 7.) ORA selects a slightly longer time period, that project need must be shown "prior to 2008". (ORA Opening Brief at 17.)

> "ORA recommends that if there is forecast to be no N-1/G-1 criteria violation prior to 2008, the Commission should dismiss SDG&E's application without prejudice, allowing SDG&E to resubmit an application for a CPC&N for this project at a later time when it can make a better case for the project. A good argument can be made that if there is no need for the project to meet reliability criteria by 2006. ORA merely chose the later date to be very conservative and because we think the record shows that there will be no reliability need before then." (ORA Opening Brief at 18.)

SSRC argues that a five-year planning horizon is consistent with the standard planning horizon as reflected in the ISO's grid planning process. As set forth in Exhibit 100, the ISO conducts an annual planning process involving all of the participating transmission owners ("PTOs") in California where PTOs develop and submit expansion plans that look ahead five (or more)[4] years to identify transmission, generation and operational improvements needed to satisfy reliability criteria within that planning horizon.

SSRC maintains that a "five-year planning horizon is also consistent with SDG&E's own practice when it comes to load forecasting." (SSRC Opening Brief at 11.) SDG&E witness Jack testified that five years is "the forecast horizon for the grid planning process" (RT 638:13-17) and that SDG&E generally does not conduct load forecasts that look more than five years into the future (RT 642:7-10).

SSRC contends that:

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[4] "The ISO witness indicated that the ISO has previously required PTOs to look ahead five years, but has recently extended its planning horizon to up to ten years. (Citation omitted.) SDG&E's witness indicated, however, that the utility's most recent grid planning assessment adopted a five-year planning horizon (2002-2007)." (SSRC Opening Brief at 9, fn. 6.)

> "[w]ithholding a Commission decision on a project as long as possible also makes particular sense in times of uncertainty because relevant information will tend to become available and become more certain during the period a decision is delayed. (Citations omitted.) As things return to normal, load growth will become more regular and predictable. Similarly, it will become clear which of the proposed new generation resources will come online and when. The Commission should therefore adopt a planning horizon that is no longer than what is necessary to allow it to process and take action far enough in advance to permit construction by the project's needed in-service date. (SSRC Opening Brief at 8.)

SSRC points out that "[a]lthough SDG&E claims that the ten-year horizon is justified for a "variety of reasons," it cites only one: the length of the licensing (permitting) process." (SSRC Reply Brief at 6.) According to SSRC, the "five-year planning horizon is appropriate given the expected regulatory and construction lead time for the project…. This approach to evaluating projects makes sense from an economic perspective because it eliminates the problem of paying the additional high price of having a resource come online before it is actually needed." (SSRC Opening Brief at 7-8.) SSRC argues that "SDG&E and the ISO essentially advocate for a planning horizon that is as long as necessary to justify the Valley-Rainbow Project " without providing a "clear or reasoned" rationale. (SSRC Reply Brief at 5.) According to SSRC, the Commission should not "adopt such a result-oriented approach to the planning horizon issue." (SSRC Reply Brief at 5.)

SSRC also attacks the ten-year planning horizon because SDG&E and the ISO advocate for:

> "lopsided assumptions regarding future load and resources that inappropriately favor a 'need' finding…. [T]he ISO and SDG&E would have the Commission assume that SDG&E's load growth will continue rapidly and steadily within the ten-year planning

> horizon they advocate and also assume that no new generation resources would be added during that same period. This assumption is contrary to evidence of record -- which indicates that the pool of available in-basin generation will expand during the next ten years -- and is therefore conservative in the extreme. It is also clearly inappropriate to artificially fix the supply side of the equation for ten years as SDG&E and the ISO have done, while simultaneously allowing the demand side to increase dramatically, as this will tend to create and / or overstate reliability problems." (SSRC Reply Brief at 7-8.)

SSRC summarizes its position as follows:

> "In sum, five years (2001-2006) is the appropriate planning horizon for the Commission's analysis of SDG&E's reliability justification for the Valley-Rainbow Project. If the Commission were to find a reliability need within that five-year period, it should (in phase 2) look out 10-20 years to ensure that the proposed project is the best means of addressing the identified reliability need. If the Commission finds no need for the Valley-Rainbow Project within the five-year planning horizon, it should reject SDG&E's CPCN application at this "need" phase of this proceeding. To do otherwise, would be inconsistent with the principles of good planning." (SSRC Opening Brief at 14.)

6.1.0. Discussion

ORA and SSRC argue that we should adopt a shorter planning horizon than SDG&E and the ISO support. SSRC argues that we should look at whether a need exists within five years from the date an application is filed, in this case, 2006. ORA agrees that a five year planning horizon is appropriate as well, but extends that date to 2008 in this case as an extra cautious approach. SSRC argues that SDG&E has based its application on a five year demand forecast (through 2006), the ISO's annual transmission planning exercises are for five year periods, and that SDG&E filed its application in 2001 when it stated that it required the Valley-Rainbow Project to be online in 2004, therefore a five-year planning horizon is most consistent with forecasting and planning exercises in the industry.

Forecasting carries with it inherent uncertainty. The farther out into the future one attempts to project, the more uncertainty exists. In this case, SDG&E and the ISO ask us to adopt a ten-year planning horizon, in other words, if demand exceeds supply under reasonably foreseeable conditions within the next ten years, we should find that the need for a project like Valley-Rainbow exists. They argue that for large capital projects like the Valley-Rainbow Project, such a planning horizon is most consistent with licensing and construction requirements.

SDG&E and the ISO concede that forecasts of both supply and demand are more uncertain as you move beyond five years in the future. As summarized by SSRC and explained in more detail in upcoming sections, SDG&E and the ISO assume that demand continues to grow consistently over the ten-year planning horizon, but they simultaneously argue that new generation supply or other potential transmission upgrades are too uncertain to be considered available to meet the demand in San Diego. The result, under their recommended planning approach, is that demand is always growing but no new generation supply or expansions of existing transmission capacity will ever be available to meet the needs of the region. This is not a realistic planning approach.

The ISO argues that we should proceed to the exploration of alternatives if we identify a need within its recommended ten-year planning horizon but suggests that we can mitigate the risk of building a resource that is not needed by establishing milestones that help manage the uncertainty over whether the project is needed. For example, the ISO suggests we grant a CPCN if we find the possibility of need within ten years, but monitor whether the need for a project such as Valley-Rainbow is accelerating or being further deferred based on development of generation resources, and adjust the schedule for pursuing the project accordingly.

Although this milestone approach has some appeal, it is easy to envision situations developing that make this approach untenable. For example, assume that we forecast a need for new resources in 2008 and we proceed in 2003 to authorize a CPCN for a transmission project and approve an Environmental Impact Report/ Environmental Impact Statement. If 1000 MW of new generation in San Diego were to come online in the 2005 to 2008 time frame, the need for a project would be deferred to <u>at least</u> 2012 using SDG&E's base case assumptions. Under the ISO's milestone approach, SDG&E would already have a CPCN to construct a project and could theoretically pursue construction more than 10 years after the environmental review for the project occurred. By that time, the environmental document would be in need of significant updating, based on changed conditions in a rapidly growing area. The additional time required to prepare a supplemental EIR/EIS would limit the value of already having a CPCN. Changed environmental conditions could eliminate a previously authorized route from being constructed. In addition, approving a CPCN without an expiration date appears to be inconsistent with the intent of legislation recently approved by the California Legislature and signed by the Governor (Senate Bill (SB) 1269, Chapter 567, Statutes 2002). SB 1269 requires construction of electric generation units to begin within one year of a generation developer receiving its permit. We find it difficult to believe that having just passed this legislation, that the Legislature would support the Commission granting open-ended authority to construct transmission lines.

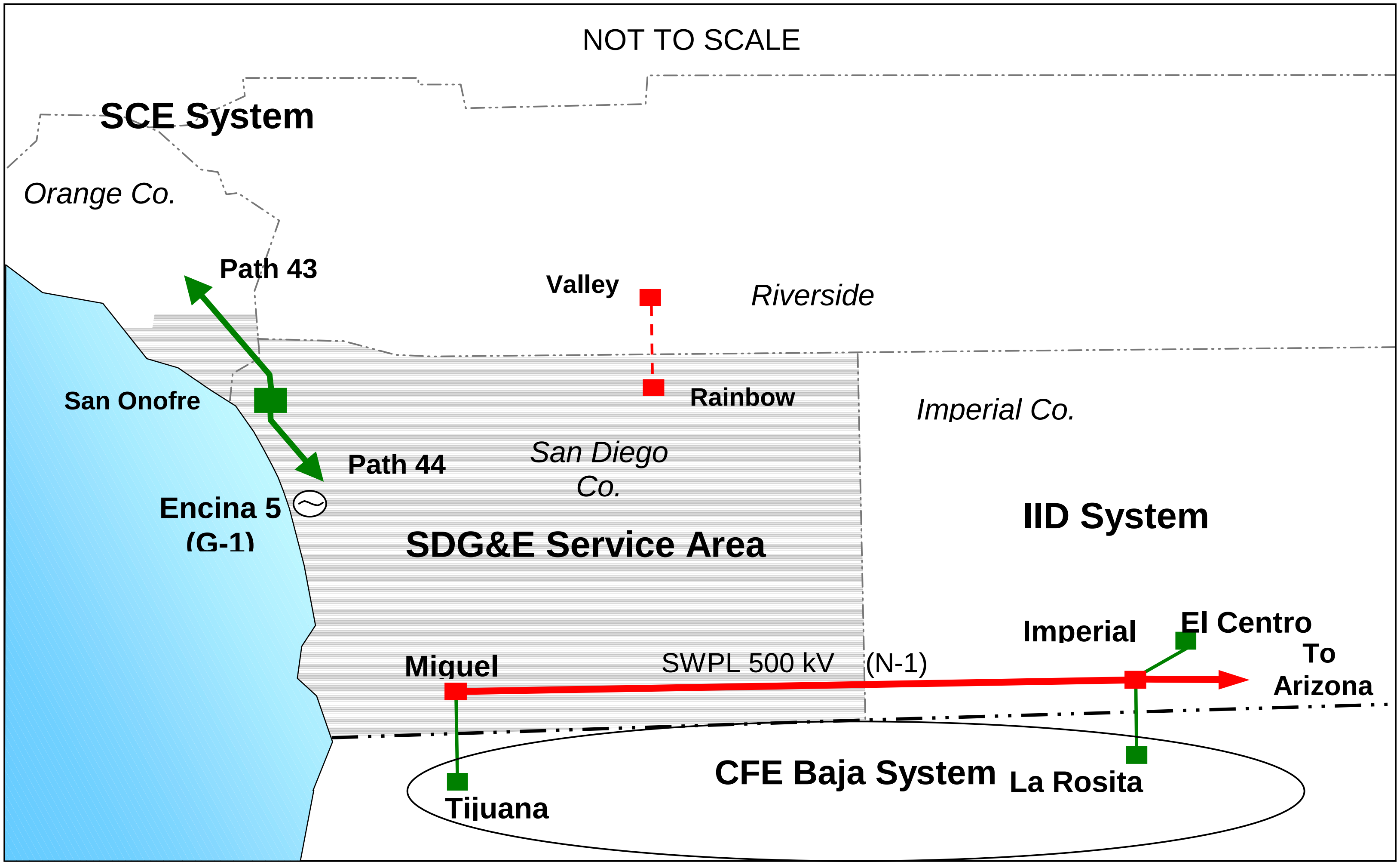
We agree with SSRC that a five-year planning horizon should be adopted for this proceeding. Although we do not have perfect knowledge of what will occur in terms of new resources or demand in the next five years, we have a much better understanding of what is reasonably expected during that time frame. We know what new generation facilities are currently permitted and under construction. We are in a much better position to develop a good understanding of these facilities, which, although never 100% certain until operating, have completed key licensing requirements and / or begun substantial construction expenditures, than we are for facilities that are being considered farther in the future.

Because of the uncertainty of new generation and potential expansion of existing transmission after five years, were we to adopt a ten-year planning horizon we would <u>always</u> find a need for a transmission capacity expansion because we could never count on new resources coming online. This cycle could result in substantial investment in resources that are never actually needed. For these reasons, we adopt a five-year planning horizon.

6.2. What is a reasonable supply forecast?

Several types of resources can serve customers in San Diego: in-basin generating resources; imports from the Southwest or Mexico over SWPL; imports from the north over Path 44 (South-of-SONGS); and imports from Mexico over Path 45. SDG&E projects that the Valley-Rainbow Project would add 750 MW of transfer capacity, above existing Path 44 levels, from north to south. The availability of resources from each of these sources impacts the supply forecast for SDG&E's service territory. Changes to in-basin generating resources (new facilities, expansions or retirements of existing units) can impact which generating unit is identified as the G-1 outage. Changes to import capability over particular transmission paths can impact which line segment is identified as the N-1 outage. A SWPL outage between Imperial Valley Substation and Miguel Substation disrupts imports from the Southwest and Mexico that normally enter SDG&E's service territory through the Imperial Valley Substation. The following map shows a graphical depiction of the SDG&E system as it relates to some of the key elements of our reliability analysis.

Exhibit 5, Chapter 2, Attachment 1
DIAGRAM OF G-1, N-1 IMPACT FOR SDG&E SYSTEM



We examine each of the key assumptions: existing in-basin generating capacity, new in-basin generating capacity, identification of the G-1 unit, imports on Path 44, and resources from Mexico.

6.2.0. Will existing in-basin generating units remain on line?

SDG&E identifies in-basin generation of 2426 MW in 2002. To arrive at its expected in-basin generation base case for 2005, SDG&E has removed 91 MW of currently operating generation, to reflect its expectation that two peaking units owned by RAMCO[5] will not operate after 2003, and an additional 67 MW of currently operating generation, to reflect its expectation that four units located on United States Navy property will not operate after 2002. All other existing in-basin generating units are assumed to remain online for the foreseeable future under SDG&E's forecast. This results in an assumption of existing in-basin generating capacity of 2268 MW in 2005 through 2012.

SDG&E's decision to eliminate the capacity of the RAMCO and Navy units is disputed by parties and is discussed below. Whether retirements of other generating units should be reflected in the assumptions for in-basin generation is also discussed.

6.2.0.1. RAMCO

RAMCO currently owns and operates two generating units, one in Escondido and one in Chula Vista, under contract with the ISO. The existing contracts are three-year contracts, which expire in 2003. SDG&E represents that the ISO is not currently negotiating with RAMCO to extend these contracts.

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[5] RAMCO is a subsidiary of PG&E National Energy Group.

SDG&E provided a copy of a letter from RAMCO to Robert Laurie at the California Energy Commission (Exhibit 5, Chapter 2, Attachment 3 at 2[6]) that states that RAMCO "has decided not to proceed with the subject Peaker Plant" as further support for why the existing RAMCO units should not be considered available. For these reasons, SDG&E has excluded the 91 MW of capacity attributable to these units.[7] In its reply brief, SDG&E argues that if the Commission is convinced that the RAMCO units will be available, it must downgrade the available capacity to 80 to 82 MW based on Exhibit 311.

The ISO, in its brief, does not actually state whether it expects the RAMCO units to be available beyond 2003 or whether it might engage in negotiations at some point in the future. However, the ISO does state "the CA ISO considers … Scenario D, which includes SDG&E's load forecast, and the RAMCO units through 2008 is the most likely." (ISO Opening Brief at 41.)

SSRC introduced a letter from RAMCO to the ISO (Exhibit 311) which states "SDG&E has incorrectly indicated that the RAMCO projects will not be available after 2003. There is no factual basis for this assumption. RAMCO

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[6] Like numerous documents introduced during this proceeding, this portion of Exhibit 5 was prepared by a non-party to this proceeding and was not offered as sworn testimony or for the truth of the information stated therein. Rather, it was offered as an indication of statements made by one of the market players whose decisions might influence the generation mix in the San Diego area.

[7] SDG&E argues that it will not be able to purchase from the RAMCO units to serve its load because RAMCO is an affiliate of Pacific Gas and Electric Company. SDG&E cites the Assigned Commissioner's Ruling in Rulemaking 01-10-024 that would prohibit utilities from entering into procurement transactions with affiliates of any California utilities as an additional reason that the RAMCO units should not be considered to be available. Since the briefs were filed in this case, D.02-08-071 issued in R.01-10-024 and did not establish any limitations on procurement from affiliates.

intends to not only bid these existing two units this year in the RMR process, but each year for the foreseeable future." SSRC argues that this statement refutes SDG&E's contentions that the RAMCO units will not be available after 2003. ORA also believes that record demonstrates that RAMCO "is eager to continue operating these plants." (ORA Opening Brief at 16.)

In addition, SSRC argues that SDG&E has not demonstrated that the RAMCO units are less efficient than other competitors in the San Diego area, which might result in removing them from the resource mix. In fact, under cross-examination by ORA, SDG&E witness Korinek testified that he believed the RAMCO units would be as efficient as other combustion turbines operating in San Diego. (RT 535:27-536:6.) SSRC points out that SDG&E assumes that other combustion turbines continue to operate under SDG&E's planning forecast, despite having no difference in efficiency compared to the RAMCO units. SDG&E's witness also admitted that SDG&E expects little change to the competitive environment for combustion turbines after 2003. (RT 436:3-438:12.) SSRC argues that "given that the RAMCO units operate in the current competitive market, it is only reasonable to assume that the units will continue to be competitive and will continue to be available in the little-changed post-2003 market." (SSRC Opening Brief at 37.)

6.2.0.2. Navy

NRG currently operates four combustion turbine units, rated by SDG&E at a total of 67 MW, as merchant generators on leased Navy land in San Diego. SDG&E does not include the 67 MW of capacity associated with the Navy units in its expected 2005 generation forecast because "SDG&E has been advised that property leases with the Navy for these plants will expire [at] the end of September 2002, and are not expected to be renewed." (Exhibit 5 at II-13.)

However, SDG&E witness Korinek indicated during cross-examination by SSRC that he had seen correspondence by NRG to the Navy, expressing NRG's desire to continue to operate the units. (RT 428:2-6, 24-26.) This letter is not a part of the record, but witness Korinek stated that he interpreted the letter to mean that the Navy was not interested in renewing the leases for the units. (RT 428:26-27.) Witness Korinek did not know whether the leases had previously expired and been renewed, although he did know that the Navy units had been operating for many years. (RT 427:19-20.)

The "ISO considers that since it is known that the Navy does not intend to extend the lease for the property, the units should be treated like units that have announced their retirement." (ISO Opening Brief at 28.) Under cross-examination by ORA, ISO witness Miller stated that the ISO would like to have the Navy units operational but that the ISO has only requested a one-month extension of the lease. (RT 859:24-860:11.) Witness Miller further stated "We haven't made the decision about whether or not we want to try to keep these units for longer term. We have the Valley-Rainbow line. We don't need to cross that bridge." (RT 860:15-18.)

Neither the ISO nor SDG&E provide any correspondence from the Navy that provides a statement of the Navy's intentions with respect to the leases, nor are copies of the leases provided to allow us to understand the lease terms or commitments. SSRC argues that SDG&E has only provided "highly unreliable non-documentary hearsay evidence" to support removal of 67 MW associated with the Navy units. (SSRC Reply Brief at 31.) SSRC and ORA also raise serious concerns that, based on ISO witness Miller's testimony described above, the ISO has not taken appropriate steps to encourage the Navy to extend the leases for the Navy units.

6.2.0.3. Retirements of Encina and South Bay

Encina units 1-5 and South Bay units 1-4 represent 1,635 MW of SDG&E's existing in-basin generation. These units began operating between 1954 and 1978 and thus are between 24 and 48 years of age. The South Bay units are operated by Duke Energy under a lease with the Port of San Diego and the City of Chula Vista, which, according to SDG&E, is scheduled to expire in 2009.

Although SDG&E and the ISO do not remove any of the South Bay or Encina units from the generation forecasts, they argue that because of the age of the units "it is important for grid planning purposes to anticipate that some of it will be retired and / or economically displaced if new, more efficient generation comes on line." (SDG&E Opening Brief at 25.) "While it is not possible to precisely predict when the older less efficient plants will be retired, it is prudent and necessary to consider the age and condition of the plants when undertaking long term planning." (Exhibit 101 at 5.) SDG&E and the ISO offer no specific guidance on when or how much capacity should be removed from the forecast to account for potential retirements or displacement.

SSRC argues that expiration of a lease does not necessarily mean that a plant will retire, as leases can be, and frequently are, renewed. SSRC also cites SDG&E's testimony to show that the expiration of the lease does not imply a loss of the capacity. SDG&E's opening and rebuttal testimony (Exhibit 1, Chapter 2, Attachment 3) indicates that Duke Energy, the operator of the South Bay units is proposing to construct new generating units in the vicinity, resulting in a net increase (over and above existing operating capacity) of 340 MW.

6.2.0.4. Reasonable existing generation assumptions

SSRC argues that "[f]or purposes of N-1 / G-1 reliability criteria planning, existing in-basin generating units should be assumed to continue to be available during the critical planning period in the absence of specific convincing evidence to the contrary." (SSRC Opening Brief at 34.) The ISO states "industry convention is that, until a generating unit officially announces its retirement, it is assumed to be available in planning studies." (Exhibit 101 at 6:1-2.) Therefore, we must determine whether the evidence that SDG&E has presented to justify removal of the RAMCO and Navy units or to assert that there will be unspecified retirements at Encina and South Bay is sufficiently convincing to warrant removal of existing capacity from our forecast of reasonably foreseeable existing generation.

In the case of both the RAMCO units and the Navy units, SDG&E and the ISO argue that without RMR designations, these units should not be assumed to be available to serve load in an N-1 / G-1 situation. However, other San Diego area generating units, for example, South Bay Unit 4 and Encina Unit 4 are not designated as RMR units but are assumed to remain available. (RT 619:19-21.) Therefore, we disagree that the sole fact that a generating unit is not designated must-run should eliminate it from the generating mix available to serve San Diego customers.

The evidence developed throughout this proceeding does not support exclusion of 91 MW of capacity associated with the RAMCO units as advocated by SDG&E. Rather, SSRC has presented convincing evidence and argument that removal of the RAMCO units is inconsistent with SDG&E's treatment of other combustion turbines and industry standards. However, SDG&E has made a legitimate argument that the amount of capacity available from these units, based on statements by RAMCO as set forth in Exhibit 311, will not be 91 MW, but closer to 80 MW. The evidence supports including 80 MW of capacity associated with the RAMCO units in the existing generation forecast.

The evidence associated with the Navy units is more troubling because of the lack of any documentation associated with the Navy's purported decision not to renew the leases for these facilities. Unlike the letter from RAMCO (Exhibit 5, Chapter 2, Attachment 3) that SDG&E provided as an indication of the operator's intent for the RAMCO units, SDG&E provided no such documentation with regard to the Navy's intent regarding the leases. SDG&E's witness could not say whether the leases had previously expired and been renewed. We conclude that SDG&E has not met its burden of proof to demonstrate that the Navy units will not be available to meet capacity requirements in future years and 67 MW of capacity associated with the Navy units should be included in the existing generation forecast.

SDG&E and the ISO presented no evidence that any of the Encina or South Bay units expect to retire. SSRC, relying on SDG&E's testimony, identified that the operator of the South Bay units is considering expanding the capacity from the units. Therefore, we make no adjustment to the existing generation forecast from Encina or South Bay to reflect unspecified retirements.

Thus, the reasonable forecast of existing in-basin generating capacity is 2268 MW + 80 MW + 67 MW = 2,415 MW.

6.2.1. Will new generating resources be built in SDG&E's service territory?

The most crucial assumptions that affect whether SDG&E will meet the N-1 / G-1 reliability criteria relate to whether or not new generation will come online in the San Diego area in the next few years. We address each of the potential sources of new generation in the San Diego region and whether it can be considered available for planning purposes.

6.2.1.1. Otay Mesa Generating Project

Otay Mesa Generating Company, LLC (Otay Mesa) is constructing a 510 MW[8] natural gas-fired combined cycle plant consisting of two gas turbines and one steam turbine that is expected to sell its output into the wholesale power market. (Exhibit 302 at 2-3.) Otay Mesa is owned by Calpine Corporation. (CEC Order No. 01-1003-01(e), Docket No. 99-AFC-5.) Calpine Energy Services, L.P. (Calpine Energy), a business unit of Calpine Corporation, holds a contract with the California Department of Water Resources (CDWR) to provide 1000 MW of firm power from July 1, 2002 through 2009. The contract obligates Calpine Energy to make "commercially reasonable efforts to complete its Otay Mesa" project and establishes certain milestones. (Exhibit 204, pp. 7-8.) The contract allows the State of California to take over development of Otay Mesa if milestones are not met.

Otay Mesa has been permitted by the California Energy Commission (CEC Order No. 01-01418-22, Docket No. 99-AFC-5), has an order directing SDG&E to interconnect it (94 FERC ¶ 61,384 (2001)), and holds a Presidential Permit to site, construct, and operate natural gas import facilities at the United States-Mexico border to meet its gas needs (96 FERC ¶ 61,178 (2001)). The natural gas pipeline that will serve Otay Mesa, North Baja Pipeline LLC, has received the relevant permits and certificates from FERC. (98 FERC ¶ 61,020 (2002).) Some minor construction on the project has occurred. According to Exhibit 217A and Exhibit 318, Otay Mesa will be online by the end of December 2004.

[8] SDG&E witness Lauckhart testified that the output of the plant is expected to be 558 MW (RT 743:23-25) and FERC has identified the output as "up to 592 MW" (94 FERC ¶ 61,384), but we use the more common 510 MW figure set forth in Exhibit 217A, CEC Power Plant Project Status.

There is significant dispute amongst the parties about whether Otay Mesa will be online by 2005, the date by which SDG&E identifies a capacity deficiency. SDG&E argues that the state of the electricity industry and Calpine's financial condition presents such uncertainty that development of Otay Mesa cannot be considered a certainty. SDG&E argues that Calpine Energy can satisfy its contractual obligation to supply 1000 MW of firm power to CDWR without construction of Otay Mesa, the contract does not require Calpine Energy to construct Otay Mesa, and therefore does little to improve the likelihood that Otay Mesa will be developed. SDG&E witness Avery testified that Otay Mesa's developer has advised SDG&E that Otay Mesa is not needed for the contract with CDWR to be fulfilled. SDG&E argues that "commercially reasonable efforts," the standard set forth in the contract with CDWR, means only that Otay Mesa will be constructed "if it is profitable or economical for Calpine to do so." (SDG&E Opening Brief at 34.) SDG&E also argues that the budget problems facing California make it highly unlikely that the State would develop Otay Mesa if project development milestones are not met. Both SDG&E and the ISO argue that, in any event, even if Otay Mesa is built, it will simply displace generation from existing older plants and therefore cannot be considered a capacity addition.

In its opening testimony, Exhibit 100, the ISO acknowledged that, consistent with standard practice, Otay Mesa should be considered as an available resource for planning purposes, because it has received a permit from the CEC. (See ISO Opening Brief at 30.) However, in its rebuttal testimony, Exhibit 101, the ISO noted that Otay Mesa's online date had been delayed and several other generating projects proposed in the San Diego area had been cancelled. These circumstances led the ISO to conclude that there is significant "uncertainty associated with plants that are not substantially under construction." (ISO Opening Brief at 30.) The ISO "remains concerned about relying on Otay Mesa to meet the need for resources in San Diego." (ISO Opening Brief at 30.) Like SDG&E, the ISO does not believe that the contract with CDWR provides any additional certainty that Otay Mesa will be constructed.

SSRC argues that standard industry practice is to include all projects that have received regulatory approvals or are permitted and under construction in the "generation resource tally for purposes of transmission planning (i.e., reliability criteria analysis)" unless "specific information indicates that the future of such plants is in question." (SSRC Opening Brief, pp. 42-43.) SSRC states:

> "The future availability of any proposed plant will, to some degree, remain uncertain until it actually begins delivering electricity to the grid. The standard industry practice… must, therefore, apply even in the face of an ordinary level of uncertainty. Departures from the practice are appropriate only for extraordinary levels and types of uncertainty regarding the future of a proposed project." (SSRC Opening Brief at 43.)

SSRC argues that there is substantial evidence in the record that Otay Mesa will be available to serve load in 2005 and beyond and that SDG&E and the ISO have failed to introduce any "convincing specific evidence" that would compel us to remove Otay Mesa from the list of resources. SSRC argues that Otay Mesa has all the necessary regulatory approvals for the project to move forward, including air emissions offsets, is under construction, and located in an area with limited local generation, all of which provide strong indicators that the project will proceed.

Unlike SDG&E and the ISO, SSRC argues that the contract with CDWR provides additional incentive for Otay Mesa to be constructed. SSRC agrees with SDG&E that Calpine Energy's contractual obligation to provide 1000 MW of power between July 1, 2002 and 2009 does not need to be met by construction of new generating units. SSRC argues that the obligation to bring Otay Mesa online is a separate obligation from the power supply obligation contained in the contract with CDWR. SSRC points to Exhibit 303, an April 22, 2002 press release from the Office of Governor Davis about the CDWR contract, which indicates "that aside from cost savings for ratepayers, the new contracts provide stronger provisions to bring new power plants online…" (Exhibit 303 at 2.) SSRC argues that the construction milestones contained in the contract, as well as monitoring and reporting provisions, are all designed to ensure that Otay Mesa is constructed so that the State of California can meet the goal set forth in the Governor's press release.

Regarding what the "commercially reasonable" efforts standard means, SSRC looks to Cal. Civ. Code §1647 which states: "A contract may be explained by reference to the circumstances under which it was made…" SSRC argues that "a court would consider the conditions that prevailed when Calpine and the State entered into the renegotiated contract" to establish whether the efforts by Otay Mesa developers were "commercially reasonable." (SSRC Opening Brief at 47.) SSRC argues that "unless it [the developer] could show that relevant conditions (e.g., energy markets, project costs) had changed considerably for the worse since the renegotiated contract was executed" the developer would not be able to establish that construction was commercially unreasonable. (SSRC Opening Brief, pp. 47-48.) SSRC argues that SDG&E and the ISO fail to acknowledge that determination of whether "commercially reasonable" efforts were made is a "fact-intensive inquiry unlikely to excuse Calpine from performance under its contract with the State." (SSRC Reply Brief at 14.) SSRC argues that little has changed in the market between when the contract was singed (April 2002), that would excuse Calpine from meeting the standard.

Like SSRC, ORA believes that Otay Mesa should be considered available for transmission planning purposes. ORA argues that the contract with CDWR substantially improves the ability of Calpine to get financing for the project because, as part of the contract, numerous governmental bodies agreed to drop legal challenges against Calpine. ORA argues that this provides Calpine, the Otay Mesa developer, "with greater revenues in the short term, greater certainty of revenues in the long term, and the support of the state in getting the power plant completed." (ORA Opening Brief at 7.)

6.2.1.2. Palomar

Sempra Energy Resources[9] has formed a company, Palomar Energy, LLC, that proposes to develop a 500 MW[10] electric generation project in Escondido called the Palomar Energy Project (Palomar). (Exhibit 217A)

The ISO does not include Palomar in its planning assessment because Palomar is still undergoing permitting at the CEC. The ISO states "[t]hus, the development of the project is very uncertain and since the project has not been permitted it should not be considered in the planning studies." (ISO Opening Brief at 35.) Like the ISO, SDG&E does not believe that Palomar should be assumed online simply because its CEC permitting process is underway. SDG&E

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[9] Sempra Energy Resources is one of eight subsidiaries of Sempra Energy. Sempra Energy is also the parent corporation of SDG&E.

[10] Exhibit 220, an excerpt from the Sempra Energy Resources website describing the Palomar project, indicates that Palomar will have an output of 550 MW and is part of a 186-acre business park development. We utilize the more conservative figure of 500 MW identified in the CEC permitting process.

also argues that if Palomar were to come online, it would simply displace less efficient generation, so it cannot be considered a net increase in generating capacity.

Because Palomar does not yet have its regulatory permits, SSRC does not argue that Palomar should be included in planning studies if the planning horizon is five years. However, SSRC argues that if the Commission adopts a planning horizon of greater than five years, it should look seriously at including Palomar in its planning assumptions. SSRC argues that none of the current evidence shows danger of Palomar being significantly delayed or cancelled. ORA agrees that the evidence points to Palomar's ongoing development efforts and argues that Palomar would meet the reliability need in the same way that Otay Mesa will.

6.2.1.3. Additional RAMCO units

SSRC introduced Exhibit 311, a letter from RAMCO to the ISO stating "RAMCO owns over 200 MW of peaking units that can be placed into service in the San Diego area in less than two years if acceptable contracts can be secured." SSRC argues on brief that

> "[t]his statement is a clear indication that RAMCO believes it would, on relatively short notice, be able to provide substantial new in-basin generation to serve SDG&E's reliability needs. RAMCO is almost certainly not the only generation developer that would be willing and able to make such additional in-basin generation resources available for procurement by or for SDG&E." (SSRC Opening Brief at 72.)

SSRC is not arguing that these resources should be included if a five-year planning horizon is used, but that they should be considered if a longer horizon is used.

6.2.1.4. Repowering and New Construction at Existing Units

> "SDG&E's interconnection queue… includes two major proposed enhancements to existing generating units in San Diego. The first project is a proposal by Cabrillo Power LLC to conduct a two-phase repowering of that company's Encina Plant.… Phase 1 of the project would produce a net increase in capacity of 610 MW and phase 2 would result in a further net increase of 315 MW.…
>
> The second project is Duke Energy's proposed South Bay generation project. Duke Energy, which currently operates the existing South Bay generating units under a contract with the Port of San Diego and City of Chula Vista, is proposing to construct new generating units in the vicinity, resulting in a net increase in generating capacity of 340 MW." (SSRC Opening Brief at 71.)

SSRC states that these units would be excluded from the available resources in a standard five-year grid planning assessment because they are only in the beginning of their planning efforts. However, SSRC recommends that if the Commission considers a planning horizon beyond five years, it consider the availability of an additional 1,265 MW of capacity from possible upgrades to existing generating units.

6.2.1.5. Reasonable new generation assumptions

Standard industry practice indicates that we should include proposed generating units that are under construction or have received regulatory permits in the resource mix for transmission planning purposes unless there is compelling evidence that the future of such plants is in question. Otay Mesa is the only unit addressed that has all regulatory approvals and is under construction. Thus, we must consider whether the evidence presented in this proceeding raises sufficient questions about the future of Otay Mesa so as to exclude its capacity from the planning process. We conclude that is does, and that Otay Mesa should not be assumed to come online in 2005.

Our concerns about the future of Otay Mesa are primarily driven by Calpine's financial situation. During closing argument SDG&E witness Avery argued that the financial condition of Calpine and numerous other generating companies was suspect and that we should not be relying on these companies to pursue long-term energy solutions. (See, generally, RT 1382-1383.) We take official notice that on April 22, 2002, the date Calpine entered into the contract with CDWR, its stock closing stock price was $11.91. As of October 15, 2002, its stock price had dropped to $2.60. As of August 1, 2002 (when Exhibit 33 was submitted), Calpine had not yet secured financing for Otay Mesa. We thus disagree with SSRC's assertion that little has changed from when Calpine signed its contract with CDWR.

As the ISO points out on brief, Otay Mesa's project status has changed frequently over the last two years, and thus we are concerned about relying on Otay Mesa to meet SDG&E's reliability requirements. In addition, as of April 12, 2002, 17 of the 36 generation projects proposed in the San Diego basin had been cancelled. (ISO Opening Brief at 30.)

The "commercially reasonable" provision in Calpine's contract with CDWR gives us little comfort that Otay Mesa will come online by 2005. As described by the ISO, this contract provision would have little meaning if Otay Mesa cannot obtain financing. "Commercially reasonable" simply means that Calpine must "act responsibly to construct Otay Mesa if it is commercially reasonable for it to do so." (ISO Opening Brief at 32.) SSRC opines that it is unlikely Calpine would be legally excused from performing under its contract with CDWR. (SSRC Reply Brief at 14.) SSRC bases its legal opinion on the assertion that little has changed in the market from when Calpine signed the CDWR contract . We decline to offer advisory opinions or otherwise speculate as to when or if Calpine is legally excused from performance. We do, however, disagree with SSRC's assertion that little has changed in the market, for the reasons discussed above.

Taken together, we find that there is sufficient uncertainty about Otay Mesa's future to exclude it from the planning horizon. Consistent with industry standards, because Palomar, additional RAMCO units, and repowering of Encina and South Bay are not sufficiently advanced in the regulatory approval process, we do not assume that they will come online for purposes of our evaluation of reliability.[11]

6.2.2. What is the relevant G-1 event under reasonable existing and new generation assumptions?

To determine the relevant G-1 event we must identify the single largest generating unit in the San Diego area. Under WECC criteria, SDG&E must plan to serve its peak demand when this generator is out of service. Encina Unit 5, with a capacity of 329 MW, is currently the relevant G-1 event. If Otay Mesa is not constructed, there is no dispute that Encina Unit 5 remains the G-1 event. Because we do not include Otay Mesa in the planning analysis, Encina Unit 5 remains the G-1 event.

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[11] SDG&E and the ISO also argued that the addition of new in-basin capacity will result in retirements of existing units. SDG&E and the ISO offered no evidence that this will occur, or how construction of a new transmission line, allowing access to less expensive resources would result in any different outcome than construction of in-basin resources.

6.2.3. Will the Path 44 (South-of-SONGS) non-simultaneous import limit remain 2500 MW?

When both Path 44 and SWPL are in service, i.e., operating simultaneously, the Path 44 rating is impacted by the flow on SWPL; WECC calls this the simultaneous import limit. WECC establishes a higher path rating for Path 44 when SWPL is not available, called the non-simultaneous import limit. Because under the N-1 condition, we assume that SWPL is out of service, we must determine what the reasonable non-simultaneous import limit is on Path 44. The current Path 44 simultaneous import limit is 2200 MW and the non-simultaneous import limit is 2500 MW.

ORA argues that Path 44 could be upgraded to provide increased import capacity and that increases to the Path 44 rating could obviate the need for the Valley-Rainbow Project. Greenpeace argues that the 2500 MW rating of Path 44 relies on inappropriate wind speed and generation assumptions North-of-SONGS, which artificially reduce the Path 44 rating. The ISO argues that changes to the Path 44 rating would entail preparation of technical studies and approval from WECC. The ISO has also identified that the path rating is based on limiting factors in the SCE transmission system. (Exhibit 6 at 9.)

From the evidence, it is clear that transmission improvements on SCE's system North-of-SONGS could result in an upgrade to the Path 44 non-simultaneous import limit rating. However, no evidence was presented to show that such improvements are currently planned and therefore, we do not modify the Path 44 non-simultaneous import limit rating for purposes of assessing SDG&E's reliability need.

6.2.4. Will resources be available from Mexico?

SDG&E can access resources from Mexico in several ways. Generators located in Mexico can directly interconnect with SDG&E substations at Miguel or

Imperial Valley. SDG&E can import power from generators located in Baja that are interconnected with the Comisión Federal de Electricidad (CFE) transmission system. These resources can reach the San Diego area either through Miguel or Imperial Valley Substations when SWPL is in service. However, when SWPL is out of service between Imperial Valley and Miguel, SDG&E can only access resources that are directly connected at Miguel Substation, connected to and able to flow through the CFE transmission system, or connected to Imperial Valley Substation and able to flow through the CFE system.

The transmission path, from the CFE system to Imperial Valley and Miguel Substations, is known as Path 45. Path 45 has recently undergone several upgrades that will allow for export of at least 400 MW to San Diego. (ISO Opening Brief at 15.) There is considerable dispute amongst the parties about what resources should be considered available from Mexico to allow SDG&E to meet its G-1/N-1 contingency.

6.2.4.1. Directly Connected Resources

ORA argues "it is critical for the Commission to understand that any new generation that would be available during an outage of SWPL west of the Imperial Valley substation would eliminate or defer the need for Valley-Rainbow." (ORA Opening Brief at 4, emphasis in original.) ORA identifies the AEP Resources units as "available to SDG&E in an N-1/G-1 contingency that involved the loss of SWPL." (ORA Opening Brief at 9.)

SSRC argues:

> "SDG&E asks the Commission to believe that new generators located in North Baja would produce significant quantities of electricity for export to California, but that neither this generation nor the associated transmission improvements would help SDG&E satisfy applicable reliability criteria. Some of the new generation resources (e.g., those interconnected solely at the Imperial Valley Substation) (footnote omitted) might not help SDG&E during an N-1/G-1 event in which the SWPL is out between Imperial Valley and Miguel. However, other new North Baja generation resources will be available to serve San Diego load during an N-1/G-1 event." (SSRC Opening Brief at 75-76.)

6.2.4.1.1. AEP Resources-Western Baja

In Exhibit 5, Chapter 2, Attachment 8, SDG&E presents a map of the "US/Mexico Border Area System & Generation Projects (2003-2005 Timeframe." The map identifies two 250 MW generating units developed by AEP Resources that are expected to come online in June 2004 and 2005 and connect at either the Otay Mesa or Miguel Substations. Exhibit 1, Chapter 2, Attachment 3 at 3, shows that these two units have completed interconnection applications on file with SDG&E and expected online dates of June 2003 and 2005. Under cross-examination, SDG&E witness Korinek stated that he did not know whether these particular units would be located in Mexico or California. (RT 596:21-28.) SDG&E does concede in its reply brief that "[p]roposed plants in western Baja, if built and interconnected with SDG&E's system in the vicinity of Otay or Miguel, could help meet SDG&E's reliability needs." (SDG&E Reply Brief at 55.) SDG&E argues that because no party has presented evidence to prove that these plants are under construction that they must be rejected for planning purposes.

6.2.4.1.2. AES/CFE Western Baja[12]

In its Opening Brief, ORA stated that a CFE representative at the June 4, 2002 technical meeting had referred to a new merchant power plant being developed by AES in western Baja designed to export power to California until local load in Baja grows sufficiently for power to be used within Mexico. No additional information about the potential project is known at this time. ORA does not argue that this potential plant should be included at this time, but that it "could be highly relevant in four or five years." (ORA Opening Brief at 9.) SDG&E agrees that there is insufficient information in the record to rely on this plant at this time.

6.2.4.2. Exports and Through-Flow Capability

The record is clear that numerous generation units are under construction in the Eastern Baja area, either connected at SDG&E's Imperial Valley Substation or CFE's La Rosita Substation. If the projects connected at La Rosita Substation have capacity above and beyond their current contractual obligations, the excess power could be available for export to the United States over Path 45. The ISO "did not identify any transmission limitation in exporting power from CFE at the 400 MW level" but "that when exports from CFE exceed 300 MW, CFE will likely trip the Imperial Valley-La Rosita 230 kV lines following a SWPL outage. This means that through-flows would be eliminated following a SWPL outage when CFE is exporting 300 MW or more but the CFE exports would remain." (Exhibit

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[12] Because there is insufficient information regarding this plant at this time, we do not know whether it would be directly connected to SDG&E's system or connected to CFE's system. However, because it would purportedly be located in western Baja, it would not face the same issues of accessing transmission capacity through Mexico so we discuss it as if it were directly connected.

102, Interim Report at 13.) However, the ISO argues that, based on historical exports from CFE to California, it is unlikely that CFE will be exporting power to California on a regular basis. The ISO states that during the summer peak in 2001, CFE exported to California only 3% of the time and provides a summary of 2000 and 2001 export statistics.

ORA counters that the ISO's review of only the years 2000 and 2001 does not demonstrate that CFE has not or will not enter into firm contracts with California. ORA points to past contracts entered into by SDG&E and SCE for delivery of 220 MW from CFE to Imperial Valley and Miguel Substations as indicative of CFE's interest and ability to deliver energy to California. (ORA Reply Brief, pp. 23-24.)

According to SSRC, the "ISO's tally of Mexican generation resources indicates that CFE has contracted and expects to contract for significant amounts of power from new generation resources in Mexico." (SSRC Opening Brief at 78.) Based on the ISO study attached to the *Summary of Workshop to Discuss Valley-Rainbow Interconnection Technical Issues*, "it appears that CFE is likely to have some extra power available to sell to SDG&E. The ISO study referred to this electricity as CFE's 'reserve margin,' which is defined as equal to [(resources) – (load) – (required operational reserve)]." (SSRC Opening Brief at 78.)

SSRC argues:

> "[a]lthough, as the ISO testimony points out, CFE has historically been a net importer of resources from the ISO system, the new generation resources coming online in Mexico are likely to allow CFE to satisfy its own needs and enter into contracts to export power to San Diego during the later years of the relevant planning horizon (e.g., 2005-2006). Moreover, it is imperative that the Commission consider the potential availability this source of power if it is inclined to look out beyond the standard five-year planning horizon." (SSRC Opening Brief at 78.)

ISO witness Miller testified that the La Rosita Power Project was substantially under construction (RT 915:1-8) with an expected output of 750 MW. SDG&E's Exhibit 5, Chapter 2, Attachment 8 map identified two additional units being developed by Intergen of 160 and 150 MW,[13] as well as two units being developed by Sempra Energy Resources of 600 MW each.

590 MW of the La Rosita Power Project, being developed by Intergen, will be interconnected at the La Rosita Substation in Mexico and 160 MW will be interconnected at Imperial Valley. 500 MW of the La Rosita output is under contract with CFE. Thus it appears that 90 MW connected at La Rosita Substation would be available for export, if it can move over the CFE system to be delivered at Miguel Substation during a SWPL outage. ORA states that an Intergen representative at the June 4, 2002 workshop stated that CFE has contracted to deliver at least 90 MW of La Rosita Power Plant capacity into California, even if SWPL is out of service west of Imperial Valley. (ORA Reply Brief at 24.) ORA argues that this 90 MW should be considered available to meet requirements during a G-1 / N-1 contingency. SSRC argues that the "resource tallies presented by SDG&E and the ISO to justify the [Valley-Rainbow] project entirely ignore this and other potential merchant generator electricity." (SSRC Opening Brief at 77.)

The ISO has identified the CFE line segment La Rosita-Rumorosa as the critical limiting segment for east to west flow. The ISO states that its Final Mexico Report (attached to the *Summary of Workshop to Discuss Valley-Rainbow*

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[13] Exhibit 218 identified that the La Rosita Power Project had secured additional financing and would be expanding the output from 750 MW to 1065 MW, and increase of 315 MW. It is unclear whether the units identified at Intergen B in Exhibit 5 (total 310 MW) are independent of this recently announced expansion or constitute the expansion.

Interconnection Technical Issues) showed that with SWPL out of service between Imperial Valley and Miguel and the Imperial Valley-La Rosita line open, CFE would only be able to reliably move 410 MW of power from La Rosita to Tijuana without overloading the La Rosita-Rumorosa line.[14] Thus, the ISO argues that because the full 590 MW of power interconnected at La Rosita cannot be assumed to flow west when SWPL is out of service, the 90 MW not committed to CFE cannot be considered available for export.

The ISO defines through-flow as the ability of the CFE 230 kV transmission system to transfer power that normally flows over SWPL directly between Imperial Valley and Miguel Substations between those same points when that SWPL line segment is out of service. Under that N-1 condition, some power can flow into San Diego from Imperial Valley by traveling over CFE's system through the La Rosita and Tijuana Substations to Miguel Substation. Much of the recent generation development to serve CFE loads is in eastern Baja, but CFE's load centers are in western Baja. Therefore, through-flow power from Imperial Valley Substation competes with generation interconnected at La Rosita for space on CFE's east to west transmission system. When SWPL is out of service, even more capacity attempts to flow through CFE to the west.

The La Rosita-Rumorosa line segment is the critical limiting segment for east to west flow for through-flow as well as exports. La Rosita-Rumorosa has a normal continuous line rating of 388 MW and an emergency rating on 430 MW. (Exhibit 102, Interim Report at 5.) If the loading on La Rosita-Rumorosa exceeds

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[14] This assumption allows the ISO to isolate the impact on the transmission system to generation connected at La Rosita. If Imperial Valley-La Rosita was closed (i.e., in service), we would expect more power to attempt to flow from east to west than the 590 MW studied, resulting in more potential line overloads.

this rating, CFE will activate a special protection system that will trip (take out of service) the Imperial Valley-La Rosita line, eliminating any through-flow from Imperial Valley. Thus the ISO argues that we cannot reasonably rely on any capacity connected at Imperial Valley Substation reaching Miguel Substation via the CFE system because overloading on the La Rosita-Rumorosa line segment will result in activation of the special protection system.

SSRC argues "that CFE would trip its connection to the United States at the Imperial Valley Substation if the amount of through flow power entering Mexico following a SWPL outage added to the pre-existing flows on CFE's east-west transmission lines were to exceed the emergency rating of the affected lines." (SSRC Opening Brief at 80-81.) SSRC points to an ISO study and testimony by ISO witness Miller that found "through flow power can be expected to be accommodated within the CFE transmission system's continuous emergency rating approximately 70 to 80 percent of the time." (SSRC Opening Brief at 81.) SSRC notes that the ISO has focused on the fact that through-flow power can be accommodated within the normal rating of La Rosita-Rumorosa only 50% of the time. SSRC argues that this "is overly conservative, however, because neither the ISO nor SDG&E has introduced any evidence that CFE would trip its connection to the United States before some element of its system reaches its continuous emergency rating." (SSRC Opening Brief at 81, fn. 42.)

SSRC argues that "there are obvious means of ensuring that the import path will remain available during *all* N-1 / G-1 events: (1) installing flow control devices to limit the amount of power flowing into the Mexican system; and (2) contracting with CFE to firm up through flow power deliveries. Although SDG&E has not done so to date, it should pursue these options to make the most of its interconnection to Mexico." (SSRC Opening Brief at 82.)

SSRC notes that "both SDG&E and the ISO downplay the fact that the outlook for through flow power would improve dramatically if CFE upgrades its east-west transmission system to serve its own reliability needs." (SSRC Opening Brief at 84.) However, SSRC points out that it "appears likely that some of the new generation resources will be located in the eastern portion of Baja California (near La Rosita). As such, CFE will have an incentive to expand its east-west transmission capacity in order to ensure that it can reliably deliver electricity to its growing load centers, which are located primarily in the West. (SSRC Opening Brief at 85.)

According to SSRC:

> "CFE will naturally seek to expand its east-west transmission lines. (Citations omitted.) As CFE makes internal transmission upgrades, it will also naturally increase the 'headroom' available on its east-west lines for through flows of power to San Diego in an N-1 / G-1 event. Although CFE's expansion of its east-west transmission system is not certain, the Commission must recognize it as a reasonable possibility, particularly if the Commission is inclined to look beyond the standard five-year planning horizon." (SSRC Opening Brief at 85-86.)

6.2.4.3. Conclusion

Insufficient information is known about the status of the AEP Resources generating units in Western Baja to allow us to consider them to be available in a G-1 / N-1 situation to meet SDG&E resource needs. No party presented any evidence to <u>either</u> call into question the expected online dates <u>or</u> to demonstrate that these projects are under construction, therefore we do not consider them at this time. However, if these units do develop, they will clearly be available to serve SDG&E loads, regardless of any through-flow constraints or limits on Path 45 import capacity because they interconnect directly to SDG&E's system and therefore are not subject to any through-flow or import limits. Likewise, insufficient information is known about the possible AES / CFE plant in Western Baja to allow us to consider it in our analysis today.

The ISO and SDG&E have taken the position that through-flow power and exports that are not 100 % certain should not be considered in the Commission's reliability analysis, even though they expect through flow power would reach Miguel Substation via Mexico during most N-1 / G-1 event conditions.

SSRC accurately sums up the through-flow issue as follows:

> "The parties' dispute regarding through flow power boils down to the following questions: (1) whether the Commission should assume these flows do not exist if it finds that they are not 100 percent certain; (2) whether the flows could and should be made certain by means of the installation of flow control devices to limit the amount of power flowing into the Mexican system and / or negotiation of appropriate wheeling contracts with CFE; and (3) whether CFE is likely to increase the capacity for through flow power as a natural by-product of upgrading its internal transmission system.
>
> SDG&E and the ISO have steadfastly insisted that the Commission should assume that these questions should (and will) all be answered in the negative…. Similarly, both SDG&E and the ISO continue to downplay the fact that the outlook for through flow power will improve dramatically when and if CFE upgrades its east-west transmission system in order to serve its own transmission needs. The project proponents have taken this position based of their assumption that CFE does not and will not have the incentives necessary to upgrade its east-west transmission system." (SSRC Reply Brief at 37-38.)

However, as SSRC points out, the ISO's Final Mexico Report:

> "indicated that the capacity of CFE's east-west transmission lines may frequently be inadequate to permit transmission of fully 590 MW of the La Rosita Power Plant's capacity (i.e., the portion of the plant's 750 MW capacity interconnected in Mexico) west to the Tijuana area during a SWPL outage between the Imperial

> Valley and Miguel Substations. If the results in this study are accurate, they indicate that CFE will soon have a strong incentive to upgrade the capacity if its east-west transmission lines in order to make room for its own east-to-west transfers. This incentive will naturally increase as more generation is added near La Rosita. (Citation omitted.)
>
> As CFE makes internal transmission upgrades, it will also naturally increase the "headroom" available on its east-west lines for through flow of power to San Diego in an N-1 / G-1 event. In short, although CFE's expansion of its east-west transmission system is not a certainty, the Commission must recognize it as a reasonable possibility, particularly if the Commission is inclined to look beyond the standard five-year planning horizon. For the foregoing reasons and those discussed in the Community Intervenors' Opening Brief, the Commission should reject the SDG&E and ISO conclusion that Mexico offers no resources that SDG&E might rely on to satisfy the N-1 / G-1 reliability criterion. (SSRC Reply Brief at 39.)

Although it is possible that CFE will make internal transmission system improvements that will allow SDG&E to rely on through-flow and exports from Mexico in the future, because these improvements have not yet occurred and we have limited information on when they might occur, we do not include them in our analysis today.

6.3. What is a reasonable demand forecast?

Demand is measured in megawatts and is the amount of energy drawn by customers at a specific time.[15] The highest load occurring in a given calendar year is called the peak demand or the annual system peak demand. The peak demand forecast is the highest expected load for the year in question.

[15] The terms "demand" and "load" can be used interchangeably.

WECC / NERC planning criteria require that the utility plan to meet its 1-in-10 year peak demand forecast when N-1 / G-1 conditions exist. Therefore, the utility is required to forecast a peak demand that would only be expected to occur once every ten years and then apply an assumed growth rate to that peak demand. The proper growth rate to utilize is in question here.

SDG&E prepares a five-year load forecast every year. In its application for approval of the Valley-Rainbow Project it utilized its October 2000 load forecast that projected growth from 2001 through 2005. SDG&E's testimony is now based on its October 2001 load forecast that projected growth from 2002 through 2006. Because of the volatility of electricity markets in 2000 and 2001, higher electricity rates, increased conservation and appliance efficiency, and a downturn in the economy, the October 2001 forecast reflected a substantial decrease from the prior year's forecast. Among other inputs, SDG&E's forecast relies on SDG&E customer energy use and price data through July 2001, a February 2001 Standard and Poor / DRI economic forecast for the San Diego region, future electricity prices as impacted by energy legislation and projected rate increases, customer class modeling, historic consumption data, demographic factors, weather factors, and line losses. Using this information, SDG&E projects system energy consumption and system peak load.

SDG&E projects a one-in-ten year system peak demand of 3992 MW in 2002. SDG&E projects a growth as follows:

Year	Growth Rate
2003	4.21%
2004	4.69%
2005	3.79%
2006	3.38%

For 2007 through 2010, SDG&E assumes a 2.5% growth rate for the one-in-ten year system peak load. SDG&E states that this is a rigorous forecasting approach using a comprehensive and accepted methodology. SDG&E also states that its peak load forecasts have historically tended to under forecast demand. (Exhibit 5, at III-7.)

SDG&E argues that its forecast may also underestimate demand due to a stronger than expected rebound in load from 2001 levels. In its rebuttal testimony, Exhibit 5, SDG&E provided data that actual weather-normalized energy consumption between October 2001 and March 2002 exceeded SDG&E's forecasted energy consumption by 2.1%. (SDG&E Opening Brief at 19.) SDG&E argues that its October 2001 load forecast is conservative given that it experienced its largest one year decline in load in 50 years during 2001 which will contribute to a faster than average growth rate in the near term.[16]

The ISO testified that it generally relies on the load forecasts provided by utilities, comparisons with CEC forecasts, and its staff load forecaster who reviews utility forecasts for reasonableness. (ISO Opening Brief at 26.) In this case, the ISO used SDG&E's load forecast when it looked at the need for a capacity expansion like the Valley-Rainbow Project. Because of the large decline in load in 2001, and the fact that there is no historical data for such a drop and the resulting rebound effect, the ISO agrees with SDG&E that a conservative approach to the load forecast is appropriate. The ISO also finds the evidence of

[16] SDG&E's weather-normalized peak load in 2001 decreased by 10.5% from 2000. (Exhibit 1 at III-1.)

consumption growth between October 2001 and April 2002 "strongly supports use of SDG&E's forecast." (ISO Opening Brief at 26.)

SSRC notes that the assumed growth rate has a major impact on whether a reliability need occurs or not. SSRC compares SDG&E's rate of load growth to SDG&E's historical forecasts, and the forecasts of other entities to argue that SDG&E's forecast growth rate is too high. SSRC argues that the demand rebound assumed by SDG&E does not have any historical precedence and that the only example of substantial and sustained growth that SDG&E could identify (1998-1990) is of limited value because of the significantly different economic conditions in place at the time. (SSRC Opening Brief at 88.) SSRC argues that both the CEC and SCE 2001 forecasts reflect a smaller growth rate over the same time period. SSRC also argues that SDG&E's load projections understate the availability of distributed generation and thus overstate the load forecast.

The evidence is clear that in 2001, SDG&E experienced the largest one-year decline in its load in 50 years. The evidence is also clear that there is no historical precedent to provide direction about how load will rebound from the 2001 level. The evidence supports a finding that electricity consumption between October 2001 and April 2002 exceeded SDG&E's October 2001 forecast by 2.1%. Although rapid growth in electricity consumption does not *per se* result in rapid peak demand growth, we find that the evidence presented supports a significant rebound in demand in SDG&E's service territory from 2001 levels. Although SSRC presented evidence that SCE forecasts over a similar time period show a slower rate of growth than SDG&E's forecast, we agree with SDG&E that SCE's 2001 change in load differed significantly from SDG&E's and does not establish that SDG&E's forecast is unreasonable. No party has presented an alternative forecast to SDG&E's, so we rely on it for purposes of assessing whether a reliability need occurs in the planning horizon.

6.4. Based on these forecasts, will SDG&E have sufficient resources to meet its customer demand over the adopted planning horizon?

Utilizing reasonably foreseeable supply and demand forecasts (existing in-basin generation of 2415 MW, no new in-basin generation, a Path 44 import limit of 2500 MW, no resources from Mexico, and SDG&E's demand forecast) we conclude that SDG&E will have a capacity deficiency in 2006 under N-1/G-1 conditions, within our adopted planning horizon of five years. The table below spells out the assumptions and resulting deficiency under N-1/G-1 conditions.

Reasonably Forseeable Forecast

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Growth Rate	%		4.21%	4.69%	3.79%	3.38%	2.50%	2.51%	2.48%	2.50%	2.50%	2.50%
Peak Demand Forecast	MW	3992	4160	4355	4520	4673	4790	4910	5032	5158	5287	5419
Existing In-Basin Capacity	MW	2415	2415	2415	2415	2415	2415	2415	2415	2415	2415	2415
New In-Basin Capacity	MW	0	0	0	0	0	0	0	0	0	0	0
G-1 Capacity	MW	329	329	329	329	329	329	329	329	329	329	329
In-Basin Resource Capacity w/o G-1	MW	2086	2086	2086	2086	2086	2086	2086	2086	2086	2086	2086

Path 44 Flow Limit	MW	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
Resources from Mexico	MW	0	0	0	0	0	0	0	0	0	0	0
N-1/G-1 Surplus/ (Deficiency)	MW	594	426	231	66	(87)	(204)	(324)	(446)	(572)	(701)	(833)

Consistent with standard industry practice, we have not included Otay Mesa in the planning analysis because there is compelling evidence that its future is in question. We do not include any generation resources in our analysis that do not already have all required permits or are not already online, though we have identified several generation units (500 MW Palomar, 500 MW AEP Resources, 925 MW repowering of Encina, 340 MW new facilities at South Bay) that may be developed or receive their regulatory permits in the future. This is also consistent with industry practice. In addition, we assume that CFE will not upgrade its east-west transmission system because there is no clear evidence. Encina Unit 5 remains the G-1 contingency under these planning assumptions. Utilizing SDG&E's peak demand forecast, which anticipates a strong rebound in demand in the next several years, is appropriate based on recent electricity consumption data in evidence.

Therefore, we find that the Valley-Rainbow Project, or an equivalent amount of capacity, is needed to meet WECC / NERC reliability criteria in the relevant five-year planning horizon thus can be justified on the basis of reliability need.

7. Economic Need

Because we find that SDG&E does have a capacity deficiency in the relevant planning horizon, we do not need to determine whether the Valley-

Rainbow Project provides economic benefits to SDG&E ratepayers and California and should be pursued as an economic project. However, both the ISO and SDG&E argued at various points in the proceeding that we should evaluate the proposed project on the basis of its economic benefits, so we undertake that analysis as well.

SDG&E submitted a report to quantify some of the likely economic benefits. (Exhibit 1, Chapter IV and Exhibit 4, Chapter IV.) The report was prepared by Henwood Energy Services, Inc. and is sometimes referred to by the parties as the Henwood Report. This report looked at the impact of the Valley-Rainbow Project on electricity market prices by modeling the difference in hourly market clearing prices in load areas with and without the project under various water scenarios, assumptions about a Path 15 transmission expansion, and new generation scenarios.

7.1. Estimated Project Costs

SDG&E originally estimated the total cost of the Valley-Rainbow Project, including necessary upgrades to its existing 230 kV system and substations to accommodate a 500 kV interconnection, to be $270,963,765. (SDG&E April 26, 2001 filing.) This figure was subsequently updated by SDG&E to $289,746,381 in 2001 dollars and $301,882,646 escalated to 2005 dollars. (Exhibit 5 at IV-6.) These figures do not include allowance for funds used during construction (AFUDC). Utilizing SDG&E's current AFUDC assumption of 8.8%, the current cost estimate for the Valley-Rainbow Project is $341,068,297 in 2005 dollars. (Exhibit 5 at IV-6.) SSRC estimated that the annual carrying charge for the project would be in the range of $50 and $60 million, depending on whether the cost included AFUDC and the specific rate used to annualize costs. (Exhibit 300 at III-5.) SDG&E estimates the annual carrying charge to be $60.7 million in 2005 dollars, assuming a 17.8% fixed charge rate. (Exhibit 5 at IV-11.) To allow for a one-to-one comparison to project benefits, which are calculated in 2001 dollars, we have converted the total cost to $318.9 million in 2001 dollars.[17] This results in an annual carrying charge of $56.8 million in 2001 dollars, assuming SDG&E's fixed charge rate of 17.8%.

SSRC and Centex Homes dispute the accuracy of SDG&E's cost estimate for the Valley-Rainbow Project. They argue that SDG&E has underestimated land acquisition and rights-of-way costs, resulting in overstatement of net project benefits.

This phase of the proceeding is not the place to establish a definitive cost estimate for the project, so we do not attempt to determine whether SDG&E's cost estimate over- or underestimates the actual project cost. For purposes of this decision, we use $56.8 million / year (in 2001 dollars) as an approximate cost against which to measure the forecasted benefits of the project and to calculate net project benefits. We view this estimate as a placeholder during this phase of the proceeding.

7.2. SDG&E's Economic Analysis

SDG&E describes its economic analysis as conservative because it does not assess the project's value as a hedge against market power. Likewise, the analysis assumes that generators will operate if their variable cost is covered, which results in lower market clearing prices. In essence, the model simulates

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[17] To calculate this figure we first calculated the amount of AFUDC assumed by SDG&E in 2005 dollars at $39.2 million ($341.1 million - $301.9 million). We then calculated the present value of the AFUDC figure in 2001 dollars at $29.1 million, using a discount rate of 8.8%, and added that amount to SDG&E's 2001 dollars project cost estimate of $289.7 million.

cost-based bidding based on individual power plant characteristics, forecasted fuel prices, and variable operation and maintenance costs.

For each scenario analyzed, SDG&E compared the system electricity costs before and after construction of a Valley-Rainbow Project under three sets of generation assumptions (Case A; Cases B and C; Cases D and E), two sets of hydro assumptions (Cases A, B, and D; Cases C and E), and with (Cases 2 and 4) and without (Cases 1 and 3) construction of a Path 15 transmission expansion. Cases 1 and 2 assumed that the Valley-Rainbow Project (or a project like it) was <u>not</u> constructed; Cases 3 and 4 assumed that the Valley-Rainbow Project was constructed. All scenarios already include 1308 MW of new generation in SDG&E's service territory, 558 MW from Otay Mesa, and 750 MW from La Rosita Power Plant in Mexico. (RT 720:10-12.) All cases also include generation that is permitted or under construction in the rest of California, 3347.5 MW in Northern California and 5307.4 MW in SCE / Zone 26. (RT 778:16-780:2.) SDG&E's scenarios for dry hydro conditions assumed that there would be six consecutive years of extreme drought, with water conditions expected to occur only once in 35 years. The premise is that by reducing congestion, new transmission capacity allows for a more efficient dispatch of generation resources, thereby lowering market clearing prices and producing project benefits.

Using the time period of 2005 through 2010, SDG&E's scenarios identified cumulative gross benefits (in 2001 dollars) to California from building the Valley-Rainbow Project as described below, using the following specific assumptions:

- Case A1 / A3 Gross benefits = $1,632,000: Median hydro conditions in all years, no additional generation capacity in California, Path 15 is not constructed
- Case A2 / A4 Gross benefits = **($844,000)**: Median hydro conditions in all years, no additional generation capacity in California, Path 15 <u>is</u> constructed

- Case B1/B3 Gross benefits= **$1,222,000**: Median hydro conditions in all years, 1700 MW additional generation capacity in SDG&E/Northern Mexico, 1531 MW additional generation in SCE/Zone 26, 2578 MW additional generation in Northern California, Path 15 <u>is not</u> constructed
- Case B2/B4 Gross benefits= **$6,130,000**: Median hydro conditions in all years, 1700 MW additional generation capacity in SDG&E/Northern Mexico, 1531 MW additional generation in SCE/Zone 26, 2578 MW additional generation in Northern California, Path 15 <u>is</u> constructed
- Case C1/C3 Gross benefits= **$93,491,000**: Dry hydro conditions in all years, 1700 MW additional generation capacity in SDG&E/Northern Mexico, 1531 MW additional generation in SCE/Zone 26, 2578 MW additional generation in Northern California, Path 15 <u>is not</u> constructed
- Case C2/C4 Gross benefits= **$8,475,000**: Dry hydro conditions in all years, 1700 MW additional generation capacity in SDG&E/Northern Mexico, 1531 MW additional generation in SCE/Zone 26, 2578 MW additional generation in Northern California, Path 15 <u>is</u> constructed
- Case D1/D3 Gross benefits= **$3,200,000**: Median hydro conditions in all years, 1700 MW additional generation capacity in SDG&E/Northern Mexico, no additional generation anywhere else in California, Path 15 <u>is not</u> constructed
- Case D2/D4 Gross benefits= **$33,199,000**: Median hydro conditions in all years, 1700 MW additional generation capacity in SDG&E/Northern Mexico, no additional generation anywhere else in California, Path 15 <u>is</u> constructed
- Case E1/E3 Gross benefits= **$340,811,000**: Dry hydro conditions in all years, 1700 MW additional generation capacity in SDG&E/Northern Mexico, no additional generation anywhere else in California, Path 15 <u>is not</u> constructed
- Case E2/E4 Gross benefits= **$504,677,000**: Dry hydro conditions in all years, 1700 MW additional generation capacity in SDG&E/Northern Mexico, no additional generation anywhere else in California, Path 15 <u>is</u> constructed

SDG&E summarizes the results in this way:

> "For the reference case scenario [A1 / A3], … existing generation, planned summer peakers [footnote omitted], and the addition of 1,308 MW of new generation is assumed. Under this reference case, the analysis shows only a small economic benefit to the consumers in the California ISO area over the period 2005-2010. However, there are numerous additional plants being proposed for the San Diego and North Baja areas, as well as the rest of the WSCC. When other scenarios of generation expansion are examined, including the impact of adverse hydroelectric conditions, the economic benefits can exceed $300,000,000 over that same 2005 – 2010 period. The value of the Valley - Rainbow Interconnect is significantly improved under the premise that as new transmission facilities are constructed and "bottlenecks" to the economic flow of electricity are reduced or eliminated, new generation is likely to be developed where it can capture the resulting market opportunities.
>
> *This analysis concludes that as more generation is built in San Diego and in Northern Baja, the economic value of the Valley - Rainbow Interconnect increases significantly. The analysis shows that ratepayers in San Diego, and within the entire area of the transmission grid controlled by the California ISO, would benefit from both the construction of more plants and the commensurate construction of the Valley - Rainbow Interconnect.*" (Exhibit 2, Chapter IV at 1-1 to 1-2, emphasis in original.)

Under cross-examination by SSRC and questioning by the ALJ, SDG&E witness Lauckhart indicated that he assumed various generation scenarios but had not analyzed the likelihood that the generation assumptions would come to pass. (See generally RT 728:7-735:24.) The analysis offered does not provide any position on the probability that any of the generation scenarios assumed would actually occur.

As we discussed earlier, we are using total costs of $318.9 million (or $56.8 million annualized in 2001 dollars) as a placeholder assumptions. Thus, SDG&E's analysis shows that in eight of the ten scenarios studied the project costs over the 2005 through 2010 time frame exceed SDG&E's estimate of economic benefits. One scenario resulted in costs and benefits being equal. The only scenario where project benefits exceeded SDG&E's projected project costs assumes that six consecutive years of one-in-35 year drought conditions occur, all new generation in California is constructed in SDG&E's service territory, and the transmission capacity on Path 15 is expanded.

SDG&E studied six scenarios under median hydro conditions. Five of the six scenarios resulted in **gross** benefits of less than $9 million over the 2005 to 2010 time period. The sixth scenario resulted in **gross** benefits of $33.2 million over the 2005 to 2010 time period. Again, the annual project carrying cost over for a single year is projected by SDG&E to be $56.8 million, more than the six-year forecast of gross benefits.

In its Opening Brief, SDG&E argues that we should be considering the gross benefits of the project, without comparison to costs, because the economic benefits are "supplemental" to the reliability benefits provided by the project.

7.3. Critiques of SDG&E's Analysis

The ISO notes that SDG&E's economic studies did not assess the potential benefits of the Valley-Rainbow Project to mitigate market power, promote supply diversity, or provide incentive for new generation development. The ISO did not itself undertake a study to assess these potential benefits but it believe that the economic benefits are greater that SDG&E's study indicates. The ISO urges the Commission to qualitatively consider these potential benefits as further rationale to approve the Valley-Rainbow Project.

ORA argues that SDG&E's position that the Valley-Rainbow Project will be needed to transport cheap generation from San Diego and Baja to the Los

Angeles basin, central and northern California is not supported by the record. ORA points out that SDG&E's argument in its economic case "assumes the opposite of what SDG&E assumes in its reliability case. Here they assume that large amounts of new generation will be built in the San Diego and north Baja region whereas in the reliability case they assume that no new generation will be built north or west of Mexicali." (ORA Opening Brief at 47.) ORA submits that generation build-out in between the low and high generation estimates relied on by SDG&E results in no need for the Valley-Rainbow Project.

ORA maintains that Valley-Rainbow should not be constructed if the annualized net present value of reduced system operating costs exceeds the annualized net present value of the Valley-Rainbow Project construction costs. ORA calculates that annualized benefits must exceed $60.7 million.

ORA states that it "looked long and hard for the economic benefit pot of gold that SDG&E describes but could not find it. In several scenarios of their economic analysis, SERA [ORA's consultant] assumed input variables that favored the project, including extreme drought years, but still could not find benefits:

> 'Additional runs … increased … Baja generation by a disproportionate 1,700 MW which tends to bias the results toward the benefits of VRTP. In these scenarios the second Mission to Miguel 230 kV line is also assumed. Further impacting these scenarios was the elimination of other generation within the region equal to the total additions made. Even with these controversial assumptions, the basic total benefits for the full six year period were forecasted to range from only 1.2 to $6 million depending upon the status of Path 15 upgrades. Even in the severe drought case the expected benefits ranged from only about $250,000 to $2.5 million for the full 6 year period.'" (ORA Reply Brief at 25-26.)

ORA argues that:

> "Although both SDG&E and the CAISO alluded in their testimony to mitigation of market power as being a benefit of Valley-Rainbow, neither party presented persuasive analysis supporting this position. Neither party introduced testimony that even attempted to quantify this alleged benefit. However, they both cite this alleged benefit of the project in their briefs.
>
> ORA agrees that additional transmission lines have the *potential* to reduce market power. However, we disagree that building expensive transmission lines is the best means of controlling market power, or that construction of such lines will *necessarily* reduce market power substantially. If market power *in 2005 and beyond* is at low levels because of more new generation, increasing diversity of generation ownership, or more effective regulation, then the incremental economic benefit that would be provided by Valley-Rainbow is very small. If market power is at high levels, then construction of Valley-Rainbow is probably not enough to bring market power down to acceptable levels and other measures will need to be taken." (ORA Reply Brief at 27, emphasis in original.)

ORA disputes the ISO claim that the Valley-Rainbow Project has a market power mitigation benefit. "To claim significant market power mitigation benefits from this line the CAISO has to demonstrate that building this line really will reduce the market power of the dominant generators. The CAISO has introduced no such analysis here; it simply assumes as a matter of faith that more transmission lines will lead to more competition." (ORA Reply Brief at 29.)

SSRC argues that:

> "SDG&E also seeks to distance itself from the results of the Henwood study by arguing that the study was conservative and therefore understated the potential economic benefits of the project. (Citation omitted.) The Commission should reject this argument, however, because the Henwood study was conducted for and presumably designed with the approval of SDG&E. If

> SDG&E felt (as it now claims) that some other approach to the economic study was appropriate in this case, it could and should have conducted such a study and submitted the results to the Commission with its opening testimony. SDG&E should not, however, be permitted to argue that some economic study that it chose not to conduct would have shown greater benefits." (SSRC Reply Brief at 48, fn. 25.)

SSRC states "[t]his argument should be recognized for what is: an acknowledgment by SDG&E of the marginal nature of the economic benefits of the project as calculated by its own study." (SSRC Reply Brief at 48.) SSRC points out that the "Valley-Rainbow Project can only be expected to produce economic benefits under a scenario (the export case) in which the project would not be needed for reliability purposes…. [A]nalysis reveals that even under the most favorable conditions and assumptions, the project offers only meager economic benefits… based on a series of unrealistic and unsupported assumptions." (SSRC Reply Brief at 49-50.) "Indeed, under most of the scenarios studied by Henwood, the project costs are between 3½ and 250 times the projected economic benefits." (SSRC Opening Brief at 99.) Under cross-examination by SSRC, SDG&E's witness clarified that, in several of the scenarios studied by SDG&E, the change in energy costs when the Valley-Rainbow Project was assumed to be built were so low as to be essentially zero. (See RT 722:224-27.)

During cross-examination of witness Lauckhart, counsel for SSRC examined the assumptions used in SDG&E's economic study.

> "Q Now, Table 1-1 indicates that for the scenarios you've identified, E2, E4, you assumed dry hydro conditions; is that correct?
>
> A Yes.

Q Okay. And when you say on this table that you assumed dry hydro conditions, does that mean you assumed dry hydro conditions in 2005, 2006, 2007, 2008, 2009 and 2010, all of those years?

A Yes.

Q Okay. And when you assume dry hydro conditions, that means that you are assuming we will experience what's referred to as a one-in-35-year drought?

A That's what we modeled here is the drought that we had in the year 2000-2001, which has been characterized as a one-in-35-year drought.

Q Meaning, statistically speaking, you would expect it to occur one year out of 35?

A Yeah, or alternatively it's the second worst in the seven[ty] years of history is what that really means.

Q Okay. So the benefit number shown here on your Table 1-1 of 504 million and some change, that's calculated assuming six years in a row of drought at a level of one -- at a level expected once every 35 years?

A Yes.

Q And in your rebuttal testimony, Exhibit 5, Chapter 5, page 25, lines 15 to 16 you state, and I quote:. . . it is very unlikely that the one-in-35-year drought would occur six years in a row. Do you see that?

A Yes." (RT 717:28-719:5.)

In testimony, SSRC's witness used the results of SDG&E's study to perform its own analysis to identify whether the source of the system energy cost benefits was a result of building transmission or generation. SSRC compared the system energy costs from SDG&E's study under various generation build out assumptions. SSRC summarizes the results of its analysis as follows:

"My analysis of the results of the Henwood study shows that between 90% and 99% of the combined benefits should actually be attributed to the existence of the additional 1700 MW of generation in San Diego / North Baja, rather than to the Valley-Rainbow Project … [I]f Path 15 is not upgraded, Henwood's analysis shows that locating an additional 1700 MW in San Diego / North Baja provides $221.7 million of economic benefits over the 6 year study period, without the Valley-Rainbow Project. These benefits represent approximately 99% of the $224.9 million of economic benefits calculated by Henwood resulting from the combination of the additional 1700 MW and the Valley-Rainbow Project, if Path 15 is not upgraded. If Path 15 is upgraded, Henwood's analysis shows that locating an additional 1700 MW in San Diego / North Baja provides $335.3 million of economic benefits over the 6 year study period, without the Valley-Rainbow Project. These benefits represent approximately 90% of the $368.5 million of economic benefits calculated by Henwood resulting from the combination of the additional 1700 MW and the Valley-Rainbow Project, if Path 15 is upgraded.

* * *

By combining the economic benefits of these two factors considered in scenarios A1 / D3 and A2 / D4 (additional generation and the Valley-Rainbow Project), SDG&E has obscured the true source of the vast majority of the benefits. Given that the vast majority of the economic benefits attributed to the combination of the addition of 1700 MW of new generation and the Valley-Rainbow Project can be achieved without the additional cost of building Valley-Rainbow (whether or not Path 15 is upgraded), it is inappropriate to attribute all of the benefits to the project. Furthermore, it is implausible to assume that the presence (or absence) of the Valley-Rainbow Project would be a critical factor in a generator's decision to locate a project in San Diego / North Baja." (Exhibit 300 at III-10-III-12, emphasis in original.)

As described by SSRC:

> "Henwood did not independently or otherwise *predict* that the significant quantities of new generation at issue would actually be built in San Diego / North Baja rather than elsewhere to respond to the market, but rather *assumed* that this would be the case for purposes of its work for SDG&E. (Citations omitted.) In fact, Henwood's study did not even determine the probability that new generation would actually be developed at the levels and locations assumed for purposes of its study….
>
> The assumption that significant quantities of new generation will be built in the San Diego / North Baja area rather than elsewhere in the WECC is highly suspect and unsupported by the record. The assumption is not supported by any probability analysis and runs contrary to the conclusions Henwood reached regarding the location of new generation prior to, and independent of, its work for SDG&E." (SSRC Opening Brief at 106-107.)

7.4. Discussion

Based on our review, we conclude that the proposed project is not cost-effective to ratepayers. Our conclusion is based on the placeholder assumption that the Valley-Rainbow Project will cost $318.9 million (or approximately $56.8 million per year on an annualized basis in 2001 dollars). The analysis indicates that project costs exceed benefits in all but one scenario. That scenario assumes six consecutive years of one-in-35 year drought conditions, all new generation being built in SDG&E's service territory, and Path 15 being expanded. As SSRC and ORA point out, the generation assumptions that we must make to find any level of benefits are completely contrary to those promoted by SDG&E and the ISO in our reliability analysis. Thus, we would have to assume that all the generation that SDG&E and the ISO argue we cannot rely on for reliability purposes is already online, plus an additional 1700 MW in the San Diego basin and northern Baja and none anywhere else in the state. This combination of assumptions is so extreme that it is totally unrealistic.

In all the scenarios where average hydro year conditions are assumed, the annual benefits of the proposed project are less than the cost, with the project costs exceeding benefits by at least $51.3 million / year or more, regardless of the level of new generation assumed.[18] The one scenario where annual benefits are greater than costs assumes one-in-35 year drought conditions for six consecutive years. As SSRC demonstrated during cross-examination of witness Lauckhart, even SDG&E's own witness does not consider it likely for this scenario to occur. SSRC also compellingly demonstrated that the vast majority of gross benefits identified by SDG&E, are attributable to generation units coming online, rather than the construction of the Valley-Rainbow Project. Neither SDG&E nor the ISO attempted to quantify the market power mitigation value they claim accrues from the project.

Based on the project costs and minimal benefits presented by SDG&E in its testimony and the problems associated with the analysis, we find that the proposed Valley-Rainbow Project is not cost-effective to ratepayers. However, because we find that there is a reliability need in 2006, we do not need to find the proposed project to be cost-effective for it to be pursued.

8. Other Issues

SCGC did not participate in this proceeding until it filed its Opening Brief. SCGC argues on brief that regardless of whether the Commission finds that the

[18] For simplicity, we assume that project benefits are spread equally over all years studied, resulting in annual benefits in the D2 / D4 scenario of $5.5 million per year, compared to annual costs of $56.8 million per year.

Valley-Rainbow Project is needed, it should eliminate the existing Sempra-wide natural gas rate that was adopted in D.00-04-060, the last Biennial Cost Allocation Proceeding for Southern California Gas Company and SDG&E, as being no longer necessary. SCGC's brief is the first time this issue was raised. EGA and SDG&E both oppose SCGC's recommendation as procedurally improper and lacking a nexus to the question of whether the Valley-Rainbow Project is needed. We agree and decline to consider SCGC's recommendation in this proceeding.

Throughout the course of the proceeding, the assigned ALJ ruled on numerous motions. We affirm the ALJ's past rulings on the various motions and deny any motion on which the ALJ did not expressly rule.

9. Conclusion

Because SDG&E will not continue to meet the WECC / NERC reliability criteria during the relevant planning horizon, SDG&E's request for a CPCN should continue to be processed. Energy Division should continue its preparation of the DEIR / DEIS for the Valley-Rainbow Project. Once the DEIR / DEIS is completed, the assigned ALJ should establish a procedural schedule to consider the alternatives to the proposed project and the requirements under §1001 et seq. for granting a CPCN.

10. Comments on Alternate Proposed Decision

The alternate proposed decision of Commissioner Duque in this matter was mailed to the parties in accordance with Public Utilities Code Section 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on ___________ and reply comments were filed on ____________.

11. Assignment of Proceeding

Commissioner Duque is the Assigned Commissioner and ALJ Cooke is the assigned ALJ in this proceeding.

Findings of Fact

1. To determine whether a reliability problem exists, WECC / NERC reliability criteria require that SDG&E be able to meet its one-in-ten year peak demand when its most critical transmission segment is out of service and the single largest in-basin generator is out of service.
2. SDG&E forecasts demand for five-year periods.
3. The ISO transmission planning exercises cover a five-year period.
4. Forecasts of both generation supply and demand are more uncertain when moving beyond five years; the longer the planning horizon utilized, the greater uncertainty exists.
5. For purposes of N-1 / G-1 reliability criteria planning, existing in-basin generating units should be assumed to continue to be available during the critical planning period in the absence of specific convincing evidence to the contrary.
6. No documentation was provided regarding the Navy's purported decision not to renew the leases for 67 MW of combustion turbines located on Navy property.
7. Under standard industry practice, proposed generating units that are under construction or have received regulatory permits are included in the resource mix for transmission planning purposes unless there is evidence that the future of such plants is in question.
8. Otay Mesa has received all regulatory approvals, but only minor construction has occurred on the project.

9. The obligation to make “commercially reasonable” efforts to develop Otay Mesa is a separate contractual obligation from delivering power to CDWR and is not eliminated when the power delivery obligation is met.

10. The current Path 44 non-simultaneous import limit is 2,500 MW.

11. Through-flow is the ability of the CFE 230 kV transmission system to transfer power that normally flows over SWPL directly between Imperial Valley and Miguel Substations between those same points when that SWPL line segment is out of service.

12. La Rosita-Rumorosa is the critical limiting line segment for east to west flow on the CFE transmission system.

13. Electricity consumption between October 2001 and April 2002 exceeded SDG&E’s October 2001 forecast by 2.1%.

14. The annual carrying charge for the Valley-Rainbow Project using SDG&E’s cost estimates is $60.7 million in 2005 dollars and $56.8 million in 2001 dollars.

15. In nine of the ten economic benefit scenarios studied, the project costs over the 2005 through 2010 time frame exceed SDG&E’s estimate of economic benefits.

16. Project benefits only exceed SDG&E’s projected project costs if six consecutive years of one-in-35 year drought conditions occur, all new generation in California is constructed in SDG&E’s service territory or northern Baja California, Mexico, and the transmission capacity on Path 15 is expanded.

17. Five of the six median hydro scenarios result in gross benefits of less than $9 million over the 2005 to 2010 time period.

18. The sixth median hydro scenario result in gross benefits of $33.2 million over the 2005 to 2010 time period.

19. The economic analysis assumes various generation scenarios but did not analyze the likelihood that the generation assumptions would come to pass.

20. In all the scenarios where average hydro year conditions are assumed, the annual benefits of the proposed project are less than the costs, with the project costs exceeding benefits by at least $51.3 million / year or more, regardless of the level of new generation assumed.

21. The vast majority of the gross benefits that SDG&E's economic study identified were attributable to generation units coming online, rather than the construction of the Valley-Rainbow Project.

22. The market power mitigation value of the proposed project has not been quantified.

Conclusions of Law

1. The Commission has jurisdiction over the proposed transmission project pursuant to Pub. Util. Code §1001 et seq.

2. Because of the uncertainty of new generation and potential expansion of existing transmission after five years, were we to adopt a ten-year planning horizon we would always find a need for a transmission capacity expansion because we could never count on new resources coming online.

3. Adoption of the ISO's milestone approach to the appropriate planning horizon could result in SDG&E pursuing construction of the proposed project more than 10 years after the environmental review for the project occurred.

4. It is reasonable to adopt a five-year planning horizon for this proceeding.

5. It is reasonable to include 80 MW associated with the RAMCO units in the existing generation forecast.

6. It is reasonable to include 67 MW associated with the Navy units in the existing generation forecast.

7. The reasonable forecast of existing in-basin generating capacity is 2,415 MW.

8. Record evidence indicates that the future of Otay Mesa is in question. Consistent with standard industry practice, it is not reasonable to assume Otay Mesa will come online in 2005.

9. Encina Unit 5 remains the G-1 event for purposes of this reliability analysis.

10. The Path 44 non-simultaneous import limit rating should not be modified for purposes of assessing SDG&E's reliability need.

11. Because CFE has not begun internal transmission system improvements and we have limited information on when they might occur, it is reasonable to exclude resources from Mexico from our reliability analysis.

12. It is reasonable to adopt SDG&E's demand forecast for our reliability analysis.

13. Utilizing reasonably foreseeable but conservative supply and demand forecasts (existing in-basin generation of 2,415 MW, no new in-basin generation, a Path 44 import limit of 2,500 MW, no resources from Mexico, and SDG&E's demand forecast), SDG&E will have a capacity deficiency in 2006 under N-1/G-1 conditions.

14. These assumptions are reasonable because they exclude Otay Mesa from the planning analysis due to concerns over Calpine's financial situation, the cancellation of generation projects and the limited value of the "commercially reasonable" standard in the contract Calpine holds with CDWR.

15. These assumptions are reasonable because they exclude any generation resources which are in question or that do not already have all required permits or are not already online.

16. These assumptions are reasonable because they assume that CFE will not upgrade its east-west transmission system.

17. These assumptions are reasonable because they utilize SDG&E's peak demand forecast which forecasts a strong rebound in demand in the next several years based on recent consumption data.

18. Additional capacity is needed to meet WECC / NERC reliability criteria in the relevant five-year planning horizon; therefore, the Valley-Rainbow Project can be justified on the basis of reliability need.

19. An annual cost of $56.8 million (in 2001 dollars) for the proposed project is a reasonable placeholder against which to measure the forecasted benefits of the project and to calculate net project benefits.

20. The generation assumptions that we must make to find any level of economic benefits are completely contrary to those promoted by SDG&E and the ISO in our reliability analysis.

21. It is not reasonable to assume there will be six consecutive years of one-in-35 year drought conditions, <u>and</u> all new generation is built in SDG&E's service territory or northern Baja California, Mexico, <u>and</u> Path 15 is expanded.

22. The proposed Valley-Rainbow Project is not cost-effective to ratepayers.

23. SCGC's recommendation to eliminate the existing Sempra-wide natural gas rate that was adopted in D.00-04-060 is procedurally improper and lacks a nexus to the question of whether the Valley-Rainbow Project is needed.

24. Because SDG&E will not continue to meet the WECC / NERC reliability criteria during the relevant planning horizon, SDG&E's request for a CPCN should continue to be processed.

25. Energy Division should continue its preparation of the DEIR / DEIS for the Valley-Rainbow Project.

O R D E R

IT IS ORDERED that:

1. This proceeding remains open to consider whether to grant San Diego Gas & Electric Company's request for a certificate of public convenience and necessity to construct the proposed Valley-Rainbow Project.

2. Energy Division shall continue its preparation of the Draft Environmental Impact Report / Draft Environmental Impact Statement for the proposed Valley-Rainbow Project.

3. The assigned Administrative Law Judge shall issue a procedural schedule for consideration of alternatives and the Pub. Util. Code § 1000 et seq. factors once the DEIR / DEIS is issued.

This order is effective today.

Dated ____________________________, at San Francisco, California.

ATTACHMENT 1
TABLE OF ACRONYMS

A.	Application
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
CA ISO	California Independent System Operator
CDWR	California Department of Water Resources
CEC	California Energy Commission
CFE	Comisión Federal de Electricidad
Commission	California Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
D.	Decision
DEIR / DEIS	Draft Environmental Impact Report / Draft Environmental Impact Statement
EGA	Electric Generator Alliance
G-1	outage of most significant in-basin generator
ISO	California Independent System Operator
KV	Kilovolt
MW	Megawatt
N-1	outage of most critical transmission network element
NERC	North American Electricity Reliability Council
ORA	Office of Ratepayer Advocates
PHC	Prehearing Conference
PTO	Participating Transmission Owner
R.	Rulemaking
RT	Reporter's Transcript
SCE	Southern California Edison Company
SCGS	Southern California generation Coalition
SDG&E	San Diego Gas & Electric Company
SONGS	San Onofre Nuclear Generating Station
SSRC	Save Southwest Riverside County, City of Temecula, Pechanga Development Corporation
SWPL	Southwest Power Link
WECC	Western Electricity Coordinating Council
WSCC	Western Systems Coordinating Council

(END OF ATTACHMENT 1)

CERTIFICATE OF SERVICE

I certify that I have by mail this day served a true copy of the original attached Draft Alternate Decision of Commissioner Duque on A.01-03-036 on all parties of record in this proceeding or their attorneys of record.

Dated October 21, 2002, at San Francisco, California.

/s/ CLAIRE JOHNSON
Claire Johnson

N O T I C E

Parties should notify the Process Office, Public Utilities Commissioner, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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If specialized accommodations for the disabled are needed, e.g., sign language interpreters, those making the arrangements must call the Public Advisor at (415) 703-2074 or TDD# (415) 703-2032 three working days in advance of the event.