In the Matter of the Application of San Diego Gas & Electric Company (U-902-E) for a Certificate of Public Convenience and Necessity For the Sunrise Powerlink Transmission Project

Application No. 06-08-010
Exhibit No.: ______________

CHAPTER 12

FEASIBILITY AND COST-EFFECTIVENESS CONSIDERATIONS OF NON-SUNRISE ALTERNATIVES

Confidentiality Key

Purple Font = Analysis and Evaluation of Proposed RPS Projects (Matrix Category VII.G)

Red Font = Contract T&C's (Matrix Category VII.G)

Green Font = Bid Information (Matrix Category VIII.A)

Burgundy Font = Procurement Percentage/Net Short Position (Matrix Category V.C)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

March 12, 2008

Updated on April 15, 2008

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CHAPTER 12

I. INTRODUCTION

The DEIR identifies three alternatives as "environmentally superior" to any permutation of Sunrise: (1) the "New In-Area, All-Source Generation Alternative"; (2) the "New In-Area Renewable Generation Alternative"; and (3) the "LEAPS Transmission-Only Alternative".[1] The DEIR (at ES-4) says these options are "reasonably expected to occur in the future" if Sunrise is not approved.

The description of the generation and related necessary transmission components in each of these alternatives is found in Chapter 2.

As described fully below, the feasibility of Aspen's in-area, All Source Generation Alternative and in-area Renewable Generation Alternative are questionable at best, as they rely on several proposed generation facilities that are uncertain or have been completely abandoned by developers because of strong local opposition, as well as on the unproven ability to greatly expand solar photovoltaic generating capability. Further, the facts assumed by Aspen for its in-area Renewable Generation Alternative are clear evidence that this alternative is highly uneconomic for ratepayers, falls short of filling the reliability deficit, and could not be implemented in time to meet the reliability deficiency forecast for 2010. As described fully below, these same concerns equally apply to Aspen's LEAPS Transmission-Only Alternative.

A. Aspen's "In-Area, All Source Generation Alternative"

1. Aspen's "In-Area, All Source Generation Alternative" is not feasible and is contrary to the CAISO's planning guidelines and Commission precedent

[1] Throughout this Chapter 12, the "LEAPS Transmission-Only Alternative" is called the TE/VS Interconnect.

In forecasting generation supply for purposes of meeting reliability needs, assumptions must be made about what new generation will be on line to meet demand in the future. The CAISO Committee on Grid Planning Policies and Processes provides guidelines on how these assumptions should be made in analyzing the need for transmission system additions. These guidelines provide five different levels of generation development, with Level 1 as the most certain and Level 5 as the least certain. Those levels are:

Level 1: Under construction

Level 2: Regulatory approval received

Level 3: Application under review

Level 4: Starting application process

Level 5: Press release only

Attachment 12-1 (California ISO Approach on the Modeling of New Generation in Power Flow Cases, at p. 1 (April 16, 2004)). According to this CAISO Committee, in five-year planning cases, "only generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study should be modeled in the initial power flow case." In ten-year planning cases, "only generation that is under construction or has received regulatory approval (Levels 1 and 2) should be modeled in the area of interest in the initial power flow case. If additional generation is required to achieve an acceptable initial power flow case, then generation from Levels 3, 4, and 5 can be used but only if they are outside the area of study so that their impact on the facility addition requirements will be minimized." *Id.*

In its *Valley Rainbow Decision*, the Commission considered what assumptions about new generation were reasonable in assessing the need for a transmission line project. The CPUC concluded that "[s]tandard 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."[2] In its *Jefferson-Martin Decision*, the Commission confirmed this standard, finding that: "Inclusion of the four CCSF turbines in the resource mix used to assess need for the Jefferson-Martin project would not be consistent with the ISO's guidelines for either five-year or ten-year planning cases, since they have not received regulatory permits. We take official notice of information on the CEC's website indicating that an Application for Certification was filed … for three of the four turbines. In light of the on-going controversy about the turbines and the early stage of their certification process, we do not have sufficient confidence that the three CCSF combustion turbines subject to that application will be constructed in a timely fashion to warrant deviation from standard industry practice and include them in the resource mix used to evaluate need for the Jefferson-Martin project."[3]

The reason for these planning assumptions is that it would be imprudent to assume that new generation will be available to serve expected load unless, at a minimum, the proposed generation project has received the necessary regulatory permits. Moreover, where projected load is not expected to be reliably served in five years or less, SDG&E believes that prudent transmission planning requires only new generation that has already begun construction should be assumed to be on-line in time to serve that load.

a. The Gas Fired Generation Assumed By Aspen In Its New In-Area All-Source Generation Alternatives Is Not A Feasible Alternative To Sunrise

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[2] *Valley Rainbow Decision*, D.02-12-066 at 33.

[3] *Jefferson-Martin Decision*, D. 04-08-046, *Mimeo* at 43. The Commission further noted that no party in that proceeding even suggested that the Commission should include in the resource mix used to assess the need for the Jefferson-Martin transmission line a "previously planned Potrero Unit 7 since Mirant has withdrawn its Application for Certification at the CEC." *Id.* at 25.

Generally, Aspen's in-area All-source Generation Alternative does not reflect the difficulty of siting new generation in the San Diego load pocket. While claiming that it is "not intended to depend on the progress of contracts for individual utility projects",[4] implementation of this alternative will rely on individual projects that will become lightning rods for opposition. There is ample evidence, as shown in this proceeding, of the strong opposition to new infrastructure additions in San Diego. Simply naming various generation projects and list of substations that could house a new peaker does nothing to assure timely success at any of these locations—and is inconsistent with Commission precedent noted above, which looks at the status of known potential generation and not hypothetical projects.

While multiple locations could represent diversification of risk, there is not sufficient time from a reliability perspective to sequentially move through this list of potential generation development with the attendant risk of any project's failure necessitating consideration of other alternatives together with further delays. Nor would such an approach conform to the Commission's guidelines for procurement through RFOs. To select projects simply based on location and probability of completion would ignore this Commission's directives on least-cost, best-fit competitive procurement as outlined initially in D.04-07-029, dated July 8, 2004 and updated periodically thereafter. To attempt to begin all projects at once, rather than attempting them sequentially, would require that SDG&E potentially procuring more than its Commission-authorized needs.

This Alternative has the largest portion of the proposed new reliability capacity (the 620 MW of CCGT) being added to the system in 2010. The DEIR implies that this is possible because these projects have either submitted applications for permits and/or have a power

[4] DEIR at E.6-1

purchase agreement in place.[5] SDG&E believes this misrepresents the status of various proposed projects in the following ways:

- The South Bay Replacement Project (SBRP), as noted in the DEIR at E.6-1, has withdrawn its Application for Certification with the CEC and does not have a PPA

- The San Diego Community Power Project (SDCPP) has not submitted an Application for Certification to the CEC and does not have a PPA. In fact, the SDCPP has been in the CAISO's generator interconnection queue since November 2000. This proposed project has already attracted opposition, even at this early stage of its development. In fact, the City of Santee is fighting the proposal.[6]

- The Encina Power Plant Repowering Project if successful in its PPA negotiations, permitting, and development, only nets 222 MW based on the DEIR's assumed output of 540 MW. The project also does not have approval from the CEC for its AFC.

- On March 11, 2008, the CEC denied the Orange Grove's application for a Small Power Producer Exemption (SPPE). SDG&E undertook expedited procurement to get this peaker project online by summer 2008. With the recent CEC denial of the SPPE for the project, the online date becomes uncertain. Thus even under expedited processing, the addition of new generation is subject to unforeseen delay.

These clarifications surrounding each project call into question the likelihood of any of these projects meeting the proposed 2010 online date. It is highly unlikely that a project of this size, if begun today, could be online prior to 2012 and most likely later. Considering any of them in the resource mix used to evaluate the need for Sunrise is contrary to the CAISO Guidelines and Commission precedent discussed above.

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[5] "Other new combined cycle projects or peaker projects may not be feasible in the 2010 timeframe because they have not yet submitted applications for permits and/or they do not have power purchase agreements". Draft EIR/EIS at E.6-2

[6] *See* Notices of Ex Parte Communication of City of Santee (filed February 27, 2008 in this proceeding); San Diego Union Tribune article entitled: "San Diego's energy puzzle", dated June 24, 2007.

Moreover, even if one were to ignore Commission precedent and consider hypothetical generation units as yet unknown, such hypothetical generation would not be available in time to serve SDG&E's needs.

The length of time needed for development of a power plant depends upon the complexity of the commercial terms and technical/environmental attributes of the project. The steps include resource solicitation and evaluation, contract negotiation, regulatory approval, permitting, engineering, equipment procurement, construction, and commissioning. In SDG&E's discussions with developers, it has been made clear that, even for simple cycle units, a new project starting today would have the highest probability of completion in summer 2012, with very little room to accelerate the schedule and much risk of delay. Some of the major steps in the development cycle, which are sequential and do not run in parallel, are described below:

- The RFO Procurement Process. The process of developing a competitive solicitation in conjunction with the Procurement Review Group, CPUC Energy Division staff and the Independent Evaluator, issuing that solicitation, allowing adequate time for quality offers to be submitted, analyzing offers, shortlisting bidder and negotiating a contract and preparing a filing for Commission approval can take up to one year.

- Commission approval. This step should be allotted at least six to nine months.

- An Application for Certification filed at the California Energy Commission can take up to 18 months to process. A developer that is confident of the negotiating process and Commission approval may start this step in parallel with the RFO/Approval steps, but this is not SDG&E's experience with most developers.

- Order Long Lead-time Equipment. SDG&E is told by developers that the time required to order standard turbine-gen sets and generation step-up transformers is ~18 – 20 months. Developers will not order this equipment prior to receiving the required approvals and permits.

- Construction. After delivery of long lead-time items, the time to construct a CCGT plant is ~24-36 months.

Adding the time required for each of these sequential steps results in a development cycle for a CCGT power plant of approximately seven years. In fact, in the recent decision in the 2006 Long Term Procurement Plan, the Commission recognized this fact stating, "[r]ecent experience suggest that the time required to develop and carry-out competitive long term RFOs, then finance, permit and construct new generation resources – including a cushion to account for unanticipated delays – requires that these procurement decisions be made up to seven years in advanced of when the resources are needed".[7]

Since SDG&E would not start the procurement process for such a unit until after a final decision in the Sunrise proceeding (expected in fall 2008), the online date for this new unit could by Commission estimates alone be as late as fall of 2015, making this capacity unavailable to meet summer peak loads until 2016. Such a delay makes this in area All-source Generation Alternative infeasible.

The following table reflects new in-area conventional gas fired generation projects that would be added under Aspen's In-Area All Source Generation Alternatives. In SDG&E's estimation, the DEIR-identified gas-fired generation under this Alternative identified new projects that provide a maximum of only 515MW of incremental capacity. This illustrates the infeasibility of the Alternative.

(Remainder of page intentionally left blank.)

[7] D.07-12-052 at 21

Table 12-1

Incremental Capacity Additions Expected From DEIS by 2010

Project	Aspen's Requirement for 2010 (MW)	SDG&E's Estimate of Actual Incremental Capacity (MW)
South Bay Replacement Project	620	0[8]
San Diego Community Power Project	750	0[9]
Encina Redevelopment	540	222[10]
Margarita	99	44
Pala	99	0 to 94
Miramar (2nd unit)	49	46

[8] Developer has withdrawn CEC Application for Certification

[9] Developer has not yet submitted CEC Application for Certification, has no known PPA, and faces local opposition.

[10] Developer has filed CEC Application for Certification, but does not have necessary permits. Even if considered despite CAISO Planning Guidelines and Commission precedent, the new units cannot co-exist with all of the existing units at the site. Developer plans to shutdown existing units, when new capacity is brought online so that the net capacity gain is 222 MW based upon 540 MW delivered as assumed in the DEIR.

Borrego	15	16
Kearny Redevelopment	144	0 to 17
MMC Escondido	56	11
MMC Chula Vista	44	65 (max)
Total	2360	515 max

b. Based On SDG&E's RFO Process, The Cost Of The In-Basin Conventional Generation Facilities Is Prohibitive.

Aspen's in-area All Source Generation Alternative proposes to replace the 1000 MW of import capacity associated with the proposed Sunrise transmission line with 1000 MW of generation technologies that reflect the Commission's "Loading Order", all of which are located in the San Diego "load pocket." As noted above, the assumed 1000 MW of new generation simply does not exist and what little new generation projects are known do not meet the standards for consideration under the CAISO Guidelines and Commission precedent. However, even assuming such hypothetical generation was foreseeable, the quantitative and qualitative review of this Alternative described below demonstrates why this Alternative is inferior to the proposed Sunrise Powerlink.

A key factor to be used in choosing between this Alternative and Sunrise is the cost of building or buying new generation given that this new capacity must be electrically located in the San Diego basin as compared to the possibility of buying renewable generation without regard to location. This comparison is based strictly upon economics or the "least cost, best fit" principles of procuring resources located either in area or buying renewable generation without regard to location (as Sunrise would allow). In CONFIDENTIAL Attachment 12-2, SDG&E presents analysis of the increased cost associated with the constraint of needing to procure locally generation contemplated by the in area All-source Generation Alternative.

The spreadsheet analysis can be summarized as follows:

- Cost of Aspen's in area All-source Generation Alternative

In this analysis, the unit costs of renewable supply resources is established as described *infra* at 12.24 for this option. The cost of conventional resources is obtained by 1) using bid prices from conventional offers submitted to SDG&E in 2007; 2) using a third party estimate of the higher cost of building locally; and 3) the premium value associated with capacity located locally as discovered through SDG&E's commercial local Resource Adequacy transactions.

- Cost Economic (Remote) Supply Resources.

Once again, the unit cost of remote renewables contained in this alternative is the same as those used in the analysis described *infra* at 12.24 regarding Aspen's in area Renewable Generation Alternative. A range of costs for the capacity for the conventional resources is used, where those costs are taken from: (a) the California Energy Commission's study to examine the cost to build new generation,[11] (b) SDG&E's projected cost to build conventional resources outside of SDG&E's service area[12] based on conventional offers submitted to SDG&E in 2007,

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[11] California Energy Commission Staff Report, "COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES", dated December 2007.

[12] The Army Corp of Engineers published its Civil Works Construction Cost Index, dated September 2007, the Corps reported that California prices are 20% higher than Arizona and 11% higher than Nevada. In a WECC Resource Planning Model issued in November 2007, the developers of the model, Energy and Environmental Economics, Inc., adopted the Corp of Engineers' factors. SDG&E utilizes an average of 20% and 11% to arrive at a 16% reduction in prices for out-basin conventional resources.

and (c) SDG&E's projected cost increases to the conventional offers received in 2007.[13] CONFIDENTIAL Attachment 12-2 illustrates that the total annual incremental cost of this option compared to the Sunrise Powerlink is between $22 million and $90 million; over 20 years this incremental cost to ratepayers of Aspen's New In-Area All-Source Generation Alternative to Sunrise ranges from $444 million to $1.8 billion. This cost differential causes this option to be infeasible.

c. SDG&E's RFO process confirms that the amount of available in-basin renewable generation is small compared to the quantity assumed to exist in Aspen's in area All-source Alternative.

The quantity of renewables assumed to exist in Aspen's in-area All-Source Generation Alternative is quite small compared to the renewables to which Sunrise would provide access. This Alternative assumes that in-area renewables adds only 1.188 GWH to SDG&E's portfolio. This accounts for an increase of only 7% of SDG&E's projected retail sales in 2010 to its RPS portfolio by 2010. Since SDG&E's portfolio depends on Sunrise imports to obtain [redacted] in 2010 and [redacted] in 2011, a non-Sunrise option would result in a net loss of renewable energy for SDG&E's portfolio.

In addition, SDG&E is in negotiations with counterparties for [redacted] of additional renewable resources that would flow over Sunrise. SDG&E will need to start the lengthy RFO process to find replacements if Sunrise was not approved. Based on experience in prior RFOs, it is not certain when, at what cost – or even if – SDG&E could find sufficient replacement renewables to allow it to meet its RPS goals.

[13] The Power Capital Costs Index (PCCI) issued in February 2008 and developed by IHS Inc. and Cambridge Energy Research Associates, reported that the cost of new power plant construction in North America increased 76% over the past three years, 27% in 12 months and 19% in the most recent six months.

While the in-area All-Source Generation Alternative also calls for the use of RECs to help SDG&E meet its renewable goals without the addition of Sunrise, the simple fact remains that the Commission has not authorized the public utilities to use RECs for RPS compliance purposes. And as was stated during the Phase 1 hearings, transmission infrastructure is still needed to permit the development of substantial amounts of renewables in California or in the WECC. Finally, it is unrealistic to assume that a REC market alone can fulfill all California IOU's RPS obligations, especially as more and more states adopt a renewable standard.

d. The Proposed In-Service Date For The Solar PV Component Of The All Source Generation Alternative s Unrealistic.

As described *supra* at 12.16, while the DEIR assumes a full 210 MW build out of solar PV by 2010, given the current costs and actual installation of systems in SDG&E's territory to date, the feasibility of achieving this goal is unrealistic. This assumed amount of PV exceeds SDG&E's California Solar Initiative target of 180.3 MW over its ten year duration starting in 2007 as provided in D.06-08-028. Additionally, the California Energy Commission in its latest revised demand forecast predicts only an incremental 13 MW of nameplate capacity by 2010 and 33 MW by 2016.[14]

2. If Aspen's Hypothetical All-Source Generation Sprang Into Existence, SDG&E Transmission Upgrades Would Be Necessary And The Cost Renders This Alternative Infeasible.

The in-area All-source Generation Alternative, DEIR at E.6-1 to E.6-28, assumes a mix of conventional fossil-fuel and renewable technologies to meet the San Diego area resource needs. This Alternative assumes at least 620 MW of combined-cycle generation, 250 MW of peaking generation, and approximately 203 MW of renewable generation. A description of the

[14] California Energy Demand 2008-2018 Staff Revised Forecast, CEC-200-2007-015-SF2, November 2007, Form 1.4 at 143

interconnection and network upgrades required to accommodate this generation is set forth in Chapter 2, Section XI.

The estimated cost for the transmission upgrades necessary to accommodate the in area All-source Generation Alternative is significantly less than that to accommodate of the in area Renewable Generation Alternative. As described in Chapter 11, Table 11-5 at 11.17 through 11.18, the estimated cost for necessary transmission system upgrades for this Alternative is $433 million (nominal $).

B. Aspen's "In-Area, Renewable Generation Alternative" Is Infeasible and Fails Key Project Objectives.

Aspen's "New In-Area Renewable Generation Alternative" is not feasible and thus it should be dismissed on that ground alone. Moreover, it is enormously expensive compared to constructing Sunrise on either the Proposed Route or SDG&E's Enhanced Northern Route. Moreover, as discussed in Chapter 2, the 230 kV transmission line necessary to interconnect the assumed solar thermal facility in Anza Borrego Springs would cross ABDSP, just as Sunrise would. In this Chapter, SDG&E evaluates the costs and benefits of constructing Aspen's "New In-Area Renewable Generation Alternative." In addition, SDG&E examines the alternatives on the following grounds: (A) feasibility of timely construction; (B) whether it meets the need to ensure reliable electric service in accordance with WECC and CAISO reliability criteria; and (C) whether it assists SDG&E in meeting its Renewable Portfolio Standards and brings renewable power from the Imperial Valley to the San Diego area.

1. This Alternative Is Not Feasible Because It Assumes Speculative Projects In Fact Will Exist.

Aspen's in area Renewable Generation Alternative relies solely on the assumed development of renewable energy resources that are incremental to a baseline amount of existing and committed in-area generation. This Option can not feasibly be placed in service on a timely basis and in amounts needed to satisfy the San Diego area reliability deficiencies. None of Aspen's in basin Renewable Generation Alternative assumed generation projects should be considered feasible for SDG&E to meet San Diego area reliability requirements because they are too speculative.

As discussed above, pursuant to the CAISO Planning Guidelines and Commission precedent, new generation should not be considered in the resource mix used to evaluate the need for a new transmission line unless it is under construction for five-year planning cases or, in ten year planning cases, under construction or fully permitted. The DEIR, and Aspen's New In-Area Renewable Generation Alternative does not identify the necessary new renewable generation meeting these standards. Thus, this Alternative is contrary to Commission precedent and should be rejected on that ground alone.

2. This Assumed Intermittent Renewable Projects Do Not Meet Resource Adequacy Requirements.

This Alternative relies upon renewable generation, with almost 80% of the energy produced coming from intermittent technologies (solar thermal, solar PV and wind). Under the Commission's and CAISO's adopted Resource Adequacy "counting" convention, intermittent resources are credited with providing resource adequacy equal to only a fraction of their nameplate capacity. [15] The 1000 MW of renewable projects assumed to exist in this alternative would provide only 437 MW of Local Resource Adequacy (LRA). In contrast, Sunrise would provide a full 1000 MW reduction to the Local Resource Adequacy requirement of the San Diego load pocket.

[15] Specific formulas and methods for deriving RA values were adopted in D.04-10-035 and further refined in D.05-10-042.

Therefore, Aspen's in basin Renewable Generation Alternative fails to provide a significant portion of the important LRA resource that is provided by Sunrise. To replicate Sunrise's 1000 MW of local reliability, this option would need to either 1) nearly double the nameplate of renewables identified in the alternative (to almost 2000 MW) in order to obtain 1000 MW of local reliability, or 2) require that an additional 563 MW of new baseload generation be built within San Diego's load pocket to "backstop" the reliability of the intermittent generation.

The difficulty with the first remedy is that, as SDG&E has discussed in the Phase 1, there is currently not sufficient in-area renewable development bid into RFOs to fulfill the 1000 MW identified in this alternative. SDG&E's most recent experience from its 2007 RPS RFO reinforces this conclusion. *See* CONFIDENTIAL Attachment 12-2. Thus, there is certainly not sufficient development potential to double this capacity as Aspen assumes. In any event, relying upon renewables for reliability means that a large portion of the resources counted upon to meet peak load must be operating in a fashion consistent in the RA "counting" conventions adopted by this Commission and the CAISO. That is, these resources must be producing at their RA counting level or above during the time of peak.

3. The Timing For On-Line Dates Assumed In This Alternative Is Not Feasible.

Aspen's in area Renewable Generation Alternative describes the required 1000 MW as being added by 2016. However, the need for Sunrise is much more immediate. The largest single renewable resource – a hypothetical solar thermal plant providing nearly half of this alternatives capacity and one third of its energy -- would not be completed until 2016, if at all. Similarly, the 400 MW of assumed wind resources are also contemplated to be completed in 2016. Again with biomass, this assumed alternative assumes 50 MW in operation by 2010 with the full 100 MW in operation by 2016. Many of the projects suggested as filling this need have either been withdrawn, or to this point demonstrated an inability to meet deadlines.

Aspen assumes that the full build out of the photovoltaic portion is by 2010. Specifically, the Aspen Alternatives, DEIR at E.5-12 states that over 20,000 PV systems per year can be installed in the SDG&E system for each of the years 2008-2010. The Aspen in area Renewable Generation Alternative does not address the difficulty in siting these PV systems. Indeed, the DEIR at E.5-12 acknowledges that there is no plan in place to address the feasibility of siting this amount of PV.[16]

In order to build this portion of the alternative, SDG&E would need to ask for and receive approval from over 60,000 residential and 255 commercial customers and construct these systems in a three year period. Since 1999, SDG&E has had only 4,842 PV systems installed for a total of 33,345 kWs of nameplate capacity. This includes the 8,742 kW of nameplate capacity (one thousand photovoltaic systems) customers installed during 2007. Given the current costs and actual installation of systems in SDG&E's territory to date, the feasibility of achieving this goal of 210 MW of PV generation by 2010 is questionable at best and also exceeds SDG&E's California Solar Initiative target of 180.3 MW over its ten year duration starting in 2007 as provided in D.06-08-028. Additionally, the California Energy Commission in its latest revised demand forecast predicts only an incremental 13 MW of nameplate capacity by 2010 and 33 MW by 2016.[17]

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[16] Draft EIR page E.5-12 "...final locations would depend on the consumer."

[17] California Energy Demand 2008-2018 Staff Revised Forecast, CEC-200-2007-015-SF2, November 2007, Form 1.4 pg 143

4. **The amount of renewable potential Aspen has assumed in this alternative is not feasible.**

The supply curve presented in CONFIDENTIAL Attachment 12-3 that demonstrates the infeasibility of Aspen's in basin Renewable Generation Alternative contains important information on the availability of renewables in the San Diego load pocket. The most striking feature of that data is the fact that the supply and demand curves do not cross. That is, there are fewer gigawatt-hours or energy offered into SDG&E RPS RFO's than are contemplated in Aspen's in basin Renewable Generation Alternative. In fact, developers of out-of basin renewable projects bid nearly six times more gigawatt hours of energy than were proposed in-basin. Taking these factors into account, there is less than one half of the energy required to make this alternative a reality. While it is possible that other projects may be developed to fill the gap, this is purely hypothetical and no such further projects have been placed under a purchased power contract or even been bid into SDG&Es RPS RFO. Such projects should be considered unlikely, given that the RPS RFOs conducted since 2002 have brought forth an abundance of likely projects already. That is to say, if these hypothetical projects existed, they would likely have been bid into an RFO by now. Even if these hypothetical projects do materialize, they will take a considerable amount of time to go through the full development cycle from concept to production. Again, these observations illustrate the infeasibility of too little renewable potential being available in time to realistically and feasibly be considered alternatives to Sunrise.

Finally, Aspen's in basin Renewable Generation Alternative (as well as its in area All-source Generation Alternative) calls for 400 MW of wind as part of the alternative for Sunrise. However, this alternative includes ~50mw of existing wind as part of the 400 MW. Any alternative for an incremental transmission project (Sunrise) must be based on incremental (new) generation and not from existing renewable projects under contract and selling power currently to SDG&E, *i.e.*, the Kuumayaay project reflected in Aspen's in basin Renewable Generation Alternative (as well as in its in basin All-source Generation Alternative).

5. The Technologies Assumed In This Alternative Are Problematic.

(1) Wind Technology Development

One general concern with the 400 MW of wind contemplated in this alternative is reliance on projects that were bid into SDG&E up to three years ago that have proved difficult to develop. One major goal of Sunrise is the enhancement of reliability in the San Diego load pocket. Reliance upon projects that have had, and continue to experience a difficult path to commercial operations, is not prudent resource planning. Two of the primary difficulties that these projects face seem to be site control and the availability of transmission.

[redacted] is currently struggling with a significant reduction of their proposed site in the Bureau of Land Management (BLM) lease process. [redacted] while BLM has publicly committed to make land available to support the state's renewable energy goals, in this instance BLM has rejected the use of this land for renewable generation in favor of maintaining visual aspects of the land, prioritizing the use of part of the site for off-road vehicle enthusiasts and reservation of part of the land for Big Horn sheep habitat. Aspen's in basin Renewable Generation Alternative favors the use of BLM sites over private lands, but clearly this solution to siting is proving uncertain and potentially infeasible.

Concerning the availability of adequate transmission capacity, there has been a "chicken-and-egg" situation with regard to transmission and wind project development in eastern San Diego County. Developers are looking for the certainty that there will be sufficient transmission capacity to allow them to interconnect significant quantities of new wind generation for delivery to load. This alternative seems to assume that a connection to the Southwest Power link could be constructed to interconnect and deliver the proposed 400 MW of wind, without the addition of Sunrise. As described in Chapters 1 and 6, there appears to be substantial uncertainty with this assumption. Continued delays and uncertainty surrounding future transmission have caused at least one major wind development project to suspend activity and withdraw their previous bid to SDG&E.

In addition to concerns about the existence of sufficient transmission, cost of that transmission is also a major concern. Wind developer studies shared with SDG&E's energy procurement or merchant department have shown that significant transmission upgrades, at a cost of up to $344 million, are required for just [redacted] of new wind.[18] Most likely, this number has increased.

<u>(2) Solar Technology Development</u>

This Aspen alternative assumes the estimated site size uses the low end of estimates for solar fields. The actual land required could be twice as large.

<u>(3) Biomass Technology Development</u>

The largest technology uncertainty in this alternative is its reliance on local biomass to provide a large portion of the energy and the most reliable capacity. SDG&E made aware of local biomass developer concerns that there may be insufficient bio fuel available to supply even the three projects (~35MW) currently under contract to SDG&E. This creates serious doubts with regard to the viability of plans for 100mw of local biomass as called for in this alternative. In fact, 93MW of the 100mw of biomass in the in basin Renewable Generation Alternative will come from projects that SDG&E has been told will rely on Municipal Solid Waste (MSW) as the

[18] McClenahan, Ex., SD-5 at III-3.

sole fuel source. While current CEC Renewable Eligibility Guidelines permit the use of garbage to create renewable energy, the conversion of garbage to electricity must be done under very strict controls. [redacted] As shown above, this alternative suffers from insufficient capacity – the lack of fuel for biomass generation may increase the reliability shortfall by another 93 MW. In addition, the alternative may not supply as much renewable energy as assumed.

This alternative concentrates a large quantity of its supply with a single supplier, thus exposing this alternative to significant developer risk. Nearly 20% of the local reliability capacity provided by this alternative and 20% of the renewable energy [redacted].

[redacted]

[redacted]

[redacted] Therefore the ability of this project to deliver in a timely fashion, and the cost associated with that delivery are unknown at this time.

(5) Miramar Landfill Facility Development

The Miramar Landfill is scheduled to close in 2012 and the assumed Miramar Landfill renewable energy project does not appear to be feasible. It is unclear whether sufficient landfill gas is available to support the economics of a new 3MW project Confirming the uncertainty with Aspen's assumed project, while SDG&E has issued annual RPS RFOs since 2004, the City has not indicated through the bidding process any interest in a new landfill gas project at Miramar for SDG&E's consideration. In fact, SDG&E currently contracts with Minnesota Methane for a generating facility at the North City Water Reclamation Plant. This contract calls for landfill gas to be piped in from the Miramar Landfill to fuel the 3.7MW generator (of which only 1MW is available for export to SDG&E). [redacted].

6. Even Assuming All of the Assumed Renewable Projects Sprang Into Existence, Transmission Upgrades Would Be Necessary and Are Cost-Prohibitive.

The transmission upgrades necessary to accommodate the renewable energy projects assumed in Aspen's New In-Area Renewable Generation Alternative is set forth in Chapter 2, Section VII. As described in Chapter 2, Section VII.A, significant transmission upgrades are required to interconnect these renewable projects at an estimated cost set forth in Table 11.5 at 11.17 through 11.18 of $1.077 billion (nominal $). More importantly, it is doubtful that this resource could be considered as deliverable on a single circuit line as assumed by Aspen and capable of meeting SDG&E's RA requirements.

7. The Costs Of Aspen's In-Area Renewable Generation Alternative Compared To The Costs Of Renewables Electrically Located Elsewhere Make This Alternative Infeasible.

One key factor to be used in choosing between Aspen's in-area Renewable Generation Alternative and Sunrise, is the cost of building or buying generation with the constraints that this new capacity must be renewable and electrically located in the San Diego basin compared to the possibility of buying renewable generation without regard to location. This comparison is based upon economics or "least cost, best fit" principles where the procurement choice is either from the broader market made available by the Sunrise Powerlink, or the smaller market in a non-sunrise, local-ONLY procurement strategy. In CONFIDENTIAL Attachment 12-4, SDG&E presents analysis of the increased cost associated with a constraint for local procurement of renewables.

The spreadsheet analysis shown in this Confidential Attachment 12-4 is summarized below:

- Cost of In-Basin Renewables

Based on the nameplate capacity of each type of renewable generation identified in the alternative, SDG&E used typical capacity factors to calculate the amount of energy that will be produced by these local resources. The cost for an amount of energy (on an annual basis) is based on three factors involving a range of market observations for local renewable resources obtained from SDG&E's 2007 competitive solicitations for long-term renewable energy:[20] a) the

[20] SDG&E bids from the 2007 RPS solicitation. SDG&E acknowledges and understand that the March 3, 2008 ADMINISTRATIVE LAW JUDGE'S RULING ORDERING SAN DIEGO GAS & ELECTRIC COMPANY TO PROVIDE ADDITIONAL PHASE 2 EVIDENCE required that "SDG&E shall provide a witness to answer questions about the company's Requests for Offers". Such a witness will be available in Phase II hearings for cross examination on the areas identified

lowest price bid for each technology, b) the volume weighted average of prices bid for each technology; and c) the highest price bid for each technology.

- Cost of Remote Economical Purchased Renewable Energy

The cost of the same quantities of energy used above is developed using a range of market observations for renewable resources located outside of the San Diego load pocket obtained from SDG&E competitive solicitations for renewables. An additional case costs these remote renewable resources economically – that is, choosing the least expensive resources offered without trying to maintain the same technology mix proposed in the Alternative.

- Develop Costs of Additional Required Resource Adequacy (RA)

As discussed below, because Aspen's in basin Renewable Generation Alternative, relies upon intermittent renewables generation, it does not provide 1000 MW of capacity as qualified under the Commission's decision's or the CAISO's tariff provisions which govern Resource Adequacy (RA) requirements. Therefore, the analysis quantifies the amount of RA that needs to be acquired to "firm up" these resources to produce a full 1000 MW of Resource Adequacy. Because these resources are local, the "firming" resources would need to be local as well. Therefore, the analysis looks at the premium that would be paid under the alternative for procuring local RA compared to system RA. If Sunrise Powerlink were built it would reduce the Local Area Resource Adequacy requirements, thus allowing procurement of less expensive System RA instead of the relatively more expensive Local RA.

- Comparison

The total incremental cost increase associated with Aspen's in basin Renewable Generation Alternative compared with Sunrise is equal to the difference between "Cost In Basin" and "Cost Economic" plus the incremental cost of Resource Adequacy. (NOTE: This analysis does not quantify any additional costs that may be incurred for transmission associated with a

1000 MW build-out of local renewables, as described below). Tables A and B in Confidential Attachment 12-4 illustrate that the total annual incremental cost of Aspen's in basin Renewable Generation Alternative compared to Sunrise is between \$33 million and \$105 million; over 20 years this incremental cost to ratepayers of using an In-Basin, Renewable Generation alternative to the Sunrise Powerlink ranges from \$661 million to \$2.1 billion. These numbers translate to an increase cost of 8% to 30% if SDG&E is required to populate Aspen's in area Renewable Generation Alternative from in-basin renewable resources.

The prices used in this analysis are taken from offers into SDG&Es 2007 RPS competitive solicitation.[21] As seen in the accompanying excel worksheet (see Confidential Attachment 12-5 labeled, "Price Trend Chart"), the costs of renewables in general has been rising year to year. Since 2003, the average bid price submitted to SDG&E's RPS RFO's have increased by [redacted]. In fact, the average bid price from 2007 increased by [redacted] versus 2006 bid prices. In addition to this empirical evidence of rising prices leading up to 2007, the California Energy Commission,[22] the Power Capital Cost Index,[23] and the New York Times[24] have all

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[21] SDG&E is using the bids from the 2007 RPS solicitation. SDG&E acknowledges and understands that the March 3, 2008 ADMINISTRATIVE LAW JUDGE'S RULING ORDERING SAN DIEGO GAS & ELECTRIC COMPANY TO PROVIDE ADDITIONAL PHASE 2 EVIDENCE required that "SDG&E shall provide a witness to answer questions about the company's Requests for Offers". Such a witness will be available in Phase II hearings for cross examination on the areas identified

[22] In a June 2007 IEPR Workshop, the CEC reports that the installed cost to build new generating plants have increased across all the major technologies, including those proposed by the DEIR alternatives. Please see Attachment 3.

[23] The Power Capital Costs Index (PCCI) issued in February 2008 and developed by IHS Inc. and Cambridge Energy Research Associates, reported that the cost of new power plant construction in North America increased by 76% in three years, 27% in 12 months and 19% in the most recent six months. The PCCI, a survey that tracks the cost of building coal, natural gas, wind and nuclear power plants, also reported that a power plant that would have cost \$1 billion to build in 2000 would cost about \$2.31 billion today.

reported increased costs to build generating facilities across all technologies. The increased costs can be attributable to world-wide increase demand for raw materials, which have resulted in cost inflation for copper, nickel, stainless steel and concrete. These increases in the past few months have only served to increase the size of the premium that would be paid for local renewable generation and thus make the incremental cost of this alternative even greater. Increases in the cost of renewables can be expected to continue given 1) increased focus on mitigation of GHG, 2) potentially higher renewables mandates, 3) competition caused by the implementation of RPS mandates in neighboring states, and 4) the slow development of renewable rich resource areas due to as lack of transmission.

C. Aspen's "LEAPS Transmission-Only Alternative" is a Phantom Project That The Commission Should Not Consider as a Feasible Alternative.

Aspen's "Leaps Project Transmission and Generation Alternative", DEIR at C-64 and C-67 describes the Lake Elsinore Advanced Pumped Storage project (LEAPS). The DEIS, however, overlooks that this project is co-sponsored by The Nevada Hydro Company (TNHC) and the Elsinore Valley Municipal Water District ("EVMWD") whom have applied to FERC pursuant to Part I of the Federal Power Act ("FPA") for a hydroelectric power plant. Co-applicants propose to generate power at a new 500 MW pumped-storage facility located in the City of Lake Elsinore and in the Cleveland national Forest, including the construction of the associated 32 mile 500 kV new transmission line between the proposed Lake and Pendleton Substations as well as additional facilities described in Chapter 2, Section VIII.

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[24] The New York Times, in a July 2007 article, reported that in November 2006 Duke Energy said it would cost $3-billion to build two 800MW coal generating units. In May 2007, Duke said that it would cost $1.83-billion to build only one unit. This is a 20% increase in only 6 months.

Aspen Alternative, DEIR at C-69 concludes that the "Transmission-Only Alternative is technically, legally, and regulatory feasible." This conclusion is flawed for a number of reasons described in Chapter 1in addition to the reasons described below. In summary, SDG&E disagrees with the DEIR that the TE/VS Interconnect Alternative would even substantially meet the major project objectives of reducing costs, improving reliability, and providing access to renewables, thereby allowing SDG&E to meet its RPS goals beginning in 2010. SDG&E's finds these conclusions grossly unsubstantiated. For example, as described in Chapter 2, Section VIII.B, the TE/VS Interconnect Alternative requires substantial, costly network upgrades to meaningfully increase SDG&E's import capability in a fashion remotely comparable to Sunrise.

While TNHC has proposed in its CPCN application a TE/VS Interconnect project, the fundamental issue remains: What project is on the table, both at FERC and at the Commission. TNHC has maintained in two pending FERC proceedings (Docket P-11858 dealing with TNHC's application for a FERC hydroelectric license, and Docket ER06-278-000 dealing with TNHC's December 2005 request for incentive ratemaking) project scopes that include *both* the TE/VS Interconnect lines and the pump storage generation. However, while these two proceedings involving the combined project are pending at FERC, TNHC further has filed, and now has pending, its October 2007 CPCN application with this Commission. In this latter filing its LEAP unit is not identified by TNHC as a facility within the scope of the TE/VS Interconnect.[25] Accordingly, TNHC has not made its intentions clear to either FERC or CPUC, as well as the numerous parties in all three -- and with Sunrise, four -- pending regulatory proceedings.

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[25] In its protest to this application, dated November 29, 2008, SDG&E pointed out areas in which TNHC's economic analysis appears to include LEAPS nonetheless. See pages 11-12 and 15-16.

Black & Veatch reviewed the LEAPS Project Transmission and Generation Alternative (or "LEAPS") information included in the Proponents Environmental Assessment (EA) dated January 2008 and the Final Environmental Impact Statement (EIS) dated January 31, 2007. Based on the LEAPS Project design and permitting information in these documents, Black & Veatch developed a conceptual level project schedule for the permitting, design and construction of the LEAPS Project. In developing the LEAPS project schedule, Black & Veatch evaluated the current status and future permitting requirements; the time to perform the geotechnical investigations needed for the project design; the time to design the facilities and obtain the necessary approvals; and the time to construct the tunnels, upper reservoir, Lake Elsinore intake, powerhouse, substation and transmission interconnection to the TE/VS. The schedule developed for the LEAPS Project indicates that it is reasonable to expect full commercial operation 73 months after the FERC License is issued or the end of April 2014 assuming the FERC License is issued in April 2008. The schedule allows for 6 to 8 months to energize, check out and start up the LEAPS Substation, the LEAPS powerhouse/substation transmission line, powerhouse electrical and mechanical systems to commission the pump-turbine/motor-generator units, and fill the upper reservoir. Based on the developed schedule, the transmission line interconnection from the LEAPS substation to the TE/VS Interconnect would need to be completed and energized in early July 2013. Therefore, it is reasonable to expect that the TE/VS Interconnect would be required to energize LEAPS six to eight months before commercial operation or by July 2013.

Moreover, there exists a pending dispute at FERC in Docket ER08-654-000 over the milestone schedule set forth in an unexecuted Large Generator Interconnection Agreement filed by the CAISO and SDG&E on March 11, 2008. This dispute involves, among other things, TNHC's assertion that the date by which the TE/VS Interconnect should be placed into commercial operation is December 31, 2009. The CAISO and SDG&E have stated in their filing letter that this date is unreasonable. SDG&E has stated in this filing letter that the earliest the TE/VS Interconnect would need to be energized to accommodate TNHC's claimed fourth quarter 2011 In-Service Date for the pumped storage project would be October 2011. For the reasons described immediately above, SDG&E does not expect this claimed in-service date for LEAPs could be any earlier than during 2014. But even if TE/VS Interconnect is separable from LEAPs, given the ordinary length of the permitting process, right-of-way acquisition, long lead time procurement, and construction timing, it is estimated that a minimum of five years is required from the filing of a CPCN until the commercial in-service date of the contemplated new TE/VS Interconnect facilities and new transmission facilities required to increase SDG&E's import capability on a basis substantially comparable to Sunrise.

In light of these uncertainties in combination with other uncertainties described elsewhere in SDG&E testimony, the Commission can not consider this TE/VS Interconnect Alternative as a feasible alternative to Sunrise in meeting SDG&E's resource deficiencies in a timely fashion.

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Attachment 12-1

Generation Assumptions for Grid Planning Studies

The transmission facilities that planning studies identify as being required in a specific area of the system are determined based on technical studies that make assumptions concerning the availability of planned generation additions. The location and size of these generation additions can dramatically alter the resulting transmission plans. The ISO Planning Standards Committee was tasked with developing a standard approach to modeling this new generation in the base cases used to plan the transmission system. The approach needs to allow for the consistent development of base cases and account for the uncertainty associated with future generation development plans. Guidance on the modeling of generation in planning studies is divided into the following sections:

Section A – California ISO Approach to the Modeling of New Generation in Power Flow Cases

Section B - Generation Retirement Assumptions

Section C - Planning Scenarios for Potential Generation Retirements

Section A
California ISO Approach on the Modeling of New Generation in Power flow Cases

For the purposes of developing these assumptions, the following stages of generation development are used:

Level 1: Under construction
Level 2: Regulatory approval received
Level 3: Application under review
Level 4: Starting application process
Level 5: Press release only

After discussing this subject at several meetings, the Committee has developed the following approach toward the modeling of new generation in the initial power flow cases used to assess the need for transmission system additions:

1) Up to 1-year Operating Cases: In these cases, only generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study should be modeled in the initial power flow case.

2) 5-year Planning Cases: In these cases, only generation that is under construction (Level 1) should be modeled in the initial power flow case

3) 10-year Planning Cases: In these cases, only generation that is under construction or has received regulatory approval (Levels 1 and 2) should be modeled in the area of interest of the initial power flow case. If additional generation is required to achieve an acceptable initial power flow case, then generation from Levels 3, 4, and 5 can be used but only if they are outside of the area of study so that their impact on the facility addition requirements will be minimized.

The above modeling assumptions should normally be used to develop the initial power flow cases. However, the individual study groups will retain the flexibility to vary from the above. For example, the study group may decide to include a plant that has received regulatory approval but not initiated construction in a five-year planning case based on additional information that may be available that indicates the plant is very likely to be in-service. In addition, the initial power flow case should only be considered as a starting point and not as the definitive case for determining the required transmission upgrades. Sensitivity cases should be examined to explore the impact that changes in generation development plans will have on transmission facility requirements. Using the information from the various cases, a transmission expansion plan should be developed that reasonably accounts for uncertainty in generation development plans.

Note: This policy does not change the queuing process for generators or the current approach used by the PTO's for conducting generator connection studies.

Section B
Generation Retirement Assumptions

In planning studies, the generators shown in the following table should be modeled out of service as they are currently retired or mothballed.

Table B-1: Current Units Retired in California (3,694 MW)

Generator Name	MW	Retirement or Mothball Date	Status	Zone
Ultra Power Blue Lake	28	2001	Mothballed	NP15
High Grove Units 1-4	154	02/01/2002	Retired	SP15
Huntington Beach 5	128	09/01/2002	Retired	SP15
Division Naval Station Gas Turbine	22	10/31/2002	Retired	SP15
Old Town Naval Training	15	10/31/2002	Retired	SP15
North Island 1 (Coronado 1)	18	11/01/2002	Retired	SP15
North Island 2 (Coronado 2)	18	11/01/2002	Retired	SP15
San Bernardino Units 1 & 2	126	10/01/2002	Retired	SP15
San Gorgonio Hydro	2.2	10/01/2002	Retired	SP15
Georgia Pacific Lumber	8	11/01/2002	Retired	NP15
Etiwanda 1 & 2	264	12/31/2002	Retired	SP15
Broadway 1 & 2	73	12/31/2002	Retired	SP15
El Segundo 1 & 2	339	12/31/2002	Retired	SP15
Jefferson Smurfit Corporation	29	2/28/03	Mothballed	SP15
Sunlaw Energy - Federal	28	4/16/03	Retired	SP15
Sunlaw Energy - Growers	28	4/16/2003	Retired	SP15
Wheelabrator Martel, Inc.	13	4/28/2003	Retired	NP15
Alamitos Unit 7	134	6/7/2003	Retired	SP15
Pittsburg Units 1 - 4	167, 154, 154, 150	10/1/2003	Retired	NP15
Morro Bay Units 1 –2	2 x 171	10/31/2003	Mothballed	ZP26
Ellwood Generating Station	56	11/7/2003	Mothballed	SP15
Etiwanda Units 3 & 4	2 x 320	11/7/2003	Mothballed	SP15
Etiwanda Unit 5	120	12/31/2003	Retired	SP15
Mandalay Unit 3	120	11/7/2003	Mothballed	SP15
Southern California Sunbelt Developers, Inc. (Mojave)	17	12/1/2003	Non-Operational	SP15
Wind Farm Management, Inc.	0.4	12/1/2003	Non-Operational	SP15

Haynes 4	222	11/30/2003	Retired	SP15
Magnolia GT 5	22	01/01/2004	Retired	SP15
Olive 3, 4	56	01/01/2004	Retired	SP15

Note: The generation retirements listed in this table are based primarily on the information provided in the California Energy Commission report entitled - Electricity Infrastructure Assessment (Docket 02-IEP-01), Appendix C.

The next category of 'out-of service' units for planning study purposes is Announced Retirements. The owners of these plants have stated publicly that these plants will be retired.

Table B-2: Announced California Generation Retirements 2004 – 2008 (1,631 MW)

Generator Name	MW	Expected Retirement Date	Zone
Valley 1-4 (LADWP)	513	04/15/2004	SP15
Haynes 3	222	09/30/2004	SP15
Magnolia 3, 4	53.5	09/30/2004	SP15
Hunters Point 4	163	01/01/2006	NP15
Hunters Point GT 1	56	01/01/2006	NP15
Hunters Point 2 & 3 (synchronous condensers)	0	01/01/2006	NP 15
Mohave	1500	2006	NA
South Bay 1-4[1]	623	11/1/2009	SP15

[1] Due to the end of the lease for the site of this power plant

Section C
Planning Scenarios for Potential Generation Retirements (Sensitivity Cases)

This section details the assumptions to be used for exploratory studies intended to identify the impacts on the grid of potential unit retirements. However, it is important to note that none of the units listed in this section are currently planned to be retired. They are listed here because they are all older vintage base load units that use natural gas to generate steam and power a steam turbine. These units are much less efficient than the new combined cycle plants being constructed today. While these units may continue to operate for many years, of the units currently connected to the ISO grid, these units are believed to be the most economically vulnerable and are likely candidates for retirement. While the initial plan for examining generation retirements looks primarily at large base load generation, there are many peakers on the ISO grid that are old and inefficient and may also be likely to retire. In the future, these peakers will likely be added to the generation retirement scenarios.

The PTOs, through their annual transmission expansion planning processes will analyze retirement scenarios and develop transmission plans to address any identified reliability concerns. The purpose of conducting studies with these generating units out of service is to gain an understanding of the potential impacts on the grid of the retirements of these retirements well in advance of the actual retirement announcement. This information may, or may not, lead to the development of additional transmission additions.

In addition, LSEs will be able to use this information in their integrated resource planning and generation procurement processes, such as to decide whether to procure power from these resources, from new resources in the vicinity of the old resources, or from remote resources in conjunction with the transmission reinforcements identified in this process.

This approach to planning for retirements has been developed to enable the ISO and the PTOs to be more proactive in planning the grid. The alternative to these studies would be to simply wait until a generator announces retirement and then initiate a study. If the study determined that the generator is necessary for reliability, then an RMR contract would be used to keep the generator operating until the necessary upgrades can be placed in-service. Since it could take many years to complete the transmission project, the RMR contracts can be very expensive. A process will be developed to take this information and develop recommendations as to whether or not these potential transmission projects should be constructed

Potential Generation Retirement Scenarios

Note: none of the units listed on this page are currently planned to be retired

The following units should be modeled out of service in each of the potential generation retirement scenarios. These scenarios are to be studied as part of the annual PTO transmission expansion planning process:

San Francisco Bay Area Scenario (3711 MW)

Generator Name	MW
Contra Costa Units 6-7	672
Contra Costa Units 4-5 (condensers)	0
Pittsburg Units 5-7	1332
Moss Landing 6-7	1500
Potrero 3	207

Note: It is expected that this scenario will result in extreme technical problems that would require extensive transmission additions to correct. As a result, this scenario may need to be broken down into several scenarios to develop more reasonable cases. Creating these subsets will be part of the annual transmission expansion planning process.

Morro Bay Area Scenario (680 MW)

Generator Name	MW
Morro Bay Units 3-4	680

Ventura Scenario (1930 MW)

Generator Name	MW
Ormond Beach Units 1-2	1500
Mandalay Units 1-2	430

South Bay Sensitivity (2084 MW)

Generator Name	MW
Redondo Beach Units 5-8	1279
El Segundo Units 3-4	670
Long Beach Units 8-9	135

Orange County Scenario (2786 MW)

Generator Name	MW
Alamitos Units 1- 6	1926
Huntington Beach Units 1- 4	860

San Diego Scenario (948 MW)

Generator Name	MW
Encina Units 1-5	948

The following attachments are not included in the public version

Attachment 12-2
Attachment 12-3
Attachment 12-4
Attachment 12-5