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Commissioner	:	Dian Grueneich
Admin. Law Judge	:	Steven Weissman
DRA Witness	:	Suurkask

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

A.06-08-010

REPORT ON THE SUNRISE POWERLINK

San Diego Gas & Electric Company (SDG&E)

Phase 1 Direct Testimony
Volume 3 of 5

San Francisco, California
May 18, 2007

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1 INTRODUCTION

My name is Daniel Suurkask. I am principal of Wild Rose Energy Solutions, Inc. of Edmonton, Alberta, Canada. My qualifications are included as Appendix A to this Volume of testimony.

This chapter summarizes my findings to date with respect to the estimated economic benefits of the Sunrise Powerlink Project (hereafter "Sunrise" or "the Sunrise Project"). I explain why I believe SDG&E's energy benefits are likely overstated, and indeed small relative to the cost of Sunrise; describe DRA's efforts to obtain alternative renewable portfolio standard (RPS) compliance benefit estimates based on the CAISO framework; and describe my adaptation of SDG&E's and CAISO's reliability cost model.[1] I also provide information derived from SDG&E's energy benefits modeling regarding other issues in this case.

[1] Mr. Woodruff discusses reliability and renewable benefit modeling and presents DRA's estimates of such benefits in Volume 1 of DRA's Phase 1 Direct Testimony.

2 ENERGY BENEFITS

2.1 SDG&E Energy Benefits Modeling

In its application, SDG&E makes its case for the energy benefits related to Sunrise and compares those to wires and non-wires alternatives. To make its case, SDG&E relied on a WECC economic database[2] and a production cost tool to simulate the WECC electric system in years 2010, 2015 and 2020.[3] The economic benefits framework is consistent with that laid out in the CAISO's Transmission Economic Assessment Methodology (TEAM). It consists of calculating expected energy costs to CAISO ratepayers under a Gas Turbine (GT) Reference Case and then again under a case which included the Sunrise Project (or other alternative transmission or generation project). The difference in estimated costs to CAISO ratepayers between the Sunrise Case (or other alternative case) and the GT Reference Case provides an estimate of the value, or energy benefit, associated with Sunrise (or other alternative).

My review of SDG&E energy benefits modeling consisted of an examination of SDG&E assumptions, methodology (including tools), and results. In this review, I considered key regional (i.e. WECC) Sunrise value drivers such as fuel price and resource expansion assumptions and "local" value drivers such as Imperial Valley (IV) renewable resource expansion and San Diego import limit assumptions. I also considered Gridview capabilities and SDG&E's use of the tool, as well as the post-processing used to obtain energy benefits results.

My review has uncovered a number of deficiencies and flaws. In sum, SDG&E has seriously overestimated Sunrise's energy benefits by way of unsupportable and erroneous

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2 The source of the version of the WECC economic database SDG&E has used is the Seams Steering Group – Western Interconnect (SSG-WI). It is therefore referred to interchangeably as the SSG-WI database in my testimony. WECC of course stands for Western Electricity Coordinating Council.

3 SDG&E interpolated and extrapolated the three point estimates to obtain 40 years of results.

assumptions and through modeling biases and inconsistencies. Moreover, I have concerns about SDG&E's understanding of the data, tools, and processes that underpin its energy benefits argument for the Sunrise Project. This last point is the primary reason why I lack confidence in SDG&E's energy modeling results, and recommend that if attention is to be given to Sunrise's possible energy benefits, the CAISO's analysis, and the analysis completed by the CAISO on behalf of intervenors, is a less troublesome starting point.[4]

I will not go through the entire litany of modeling problem areas in SDG&E's energy benefits analysis. Instead, I focus on three key Sunrise value drivers, two of which consist of unsupportable assumptions, the correction of which will lead to an immediate deflation of SDG&E Sunrise energy benefit estimates, and the third of which is perhaps only a modeling quirk, but with an impact that also arouses concern. In any event, this third issue is likely to disappear upon correction of one of the two problematic assumptions previously alluded to. With these examples, I am largely able to show that the expected Sunrise energy benefits are modest, and certainly – by themselves – do not represent a pillar of the Sunrise value proposition.

2.1.1 Gas Prices: Reasonable Base or High Case Sensitivity?

One key flaw in SDG&E's analysis was the assumption of unreasonably high gas prices for its energy benefits modeling. I make this claim based on a review of several sources of gas price data.

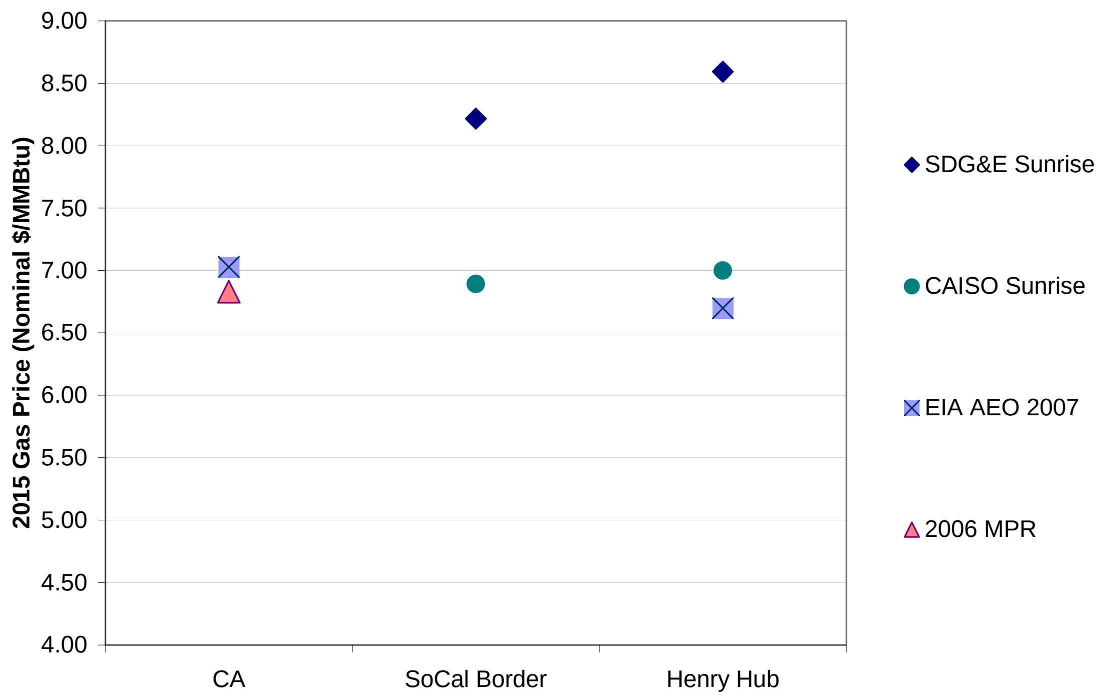
For modeling purposes, SDG&E made use of the $7.00/MMBtu (real 2005$) gas price forecast that came with its WECC economic (SSG-WI) database. By 2015, after accounting for inflation, the forecast is almost $9.00/MMBtu. The forecast is therefore

[4] C.f. A.06-08-010, Initial Testimony of the California Independent System Operator, Second Errata to Part II, April 20, 2007; A.06-08-010, Initial Testimony of the California Independent System Operator, Part III, April 20, 2007; and Initial Testimony of the California Independent System Operator, Part IV, May 14, 2007.

28 percent (or $1.89/MMBtu (2015$)) higher than the EIA's Annual Energy Outlook 2007 forecast[5] and 27 percent ($1.85/MMBtu) higher than the gas prices used to compute the Commission's 2006 Market Price Referent.[6] Based on this simple survey, SDG&E's gas prices do not appear reasonable for use in base case modeling, but are better suited instead for a "high" gas price sensitivity. Another useful point of reference is provided in Confidential Appendix B to this Volume 3. Figure 2-1 below illustrates the issue.

FIGURE 2-1

SDG&E Sunrise Powerlink 2015 Gas Price Forecast in Context
(Nominal $/MMBtu)



[5] Energy Information Administration, *Annual Energy Outlook 2007*, Supplemental Tables, Table 19. Energy Prices by Sector and Source -- Pacific, Table 104, "Lower 48 Natural Gas Production and Wellhead Prices by Supply Region."

[6] CPUC 2006 Market Price Referent

These high gas prices have a significant impact on estimated energy benefits. Gas prices drive much of the claimed Sunrise energy benefits.

For example, using the CAISO's gas price assumptions along with all the other assumptions from SDG&E's analysis causes energy benefits to fall approximately $46 million, or 44 percent.[7,8] This sensitivity identifies one of the main assumption differences between CAISO and SDG&E energy modeling results. The results in Confidential Appendix B to this Volume 3 cast further light on this matter.

2.1.2 Unreasonable WECC Resource Expansion

SDG&E has also assumed an unsupportable WECC capacity expansion plan for its modeling, including 12,000 MW of new coal plant capacity. SDG&E has attempted to justify these assumptions, and others, by pointing out that the source of its data, the SSG-WI database, was the fruit of a collaborative industry effort,[9] going as far as stating that it believes the SSG-WI database to be the "best available source of comprehensive information concerning existing generation and transmission elements and projected generation additions and transmission upgrades."[10] Even if one were to share the high esteem SDG&E has for the SSG-WI database, SDG&E should have been able to assess the problematic SSG-WI resource expansion assumptions through (1) review of existing studies that have used the SSG-WI database, (2) discussion with the analysts that put the database together, and (3) simple review of the "reasonableness" of the results, otherwise known as validation.

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7 See Part II (Second Errata) of the CAISO's Initial Testimony, pp 17-20, for the review the CAISO completed on its natural gas price assumptions.

8 SDG&E executed this simulation in response to DRA data request 6-1a.

9 See for example SDG&E response to UCAN data request 7-50.

10 A.06-08-019, "Supplemental Testimony", Chapter VII, January 26, 2007, p. 3.

(1) What SDG&E would have learned after a review of existing studies that have used the SSG-WI database. In a May 2006 study completed for the Western Governor's Association Clean and Diversified Energy Advisory Committee, the authors state:[11]

> "The SSG-WI 2015 generation and load assumptions yield a planning margin equal to 29%. In contrast, more common observed planning margins in the West are typically in the range if 10% to 15%. A planning margin around 30% suggests there is excess generating capacity in the system. Market conditions would probably discourage investors from building new generation in regions with excess capacity" (p. 54).

The authors state a little further on:

> "…the SSG-WI Reference Case had a 29% planning margin which is probably too high for conventional market practices. Accordingly the CDEAC scenarios have a higher than optimum planning margin" (p. 55).

(2) What SDG&E would have learned if they had communicated with the developers of the SSG-WI database. The analysts that developed the SSG-WI database in a recent "post-mortem" review of the SSG-WI database admit:[12]

> "[d]espite the RPS/IRP compliance, we added too much generation" (slide 35) and "[a]ggregate planning margin of 29% suggests we added too much generation….[The] [m]arket would not support/finance excessive generation capacity" (slide 38).

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[11] *Report of the Transmission Task Force*, May 2006, Western Governors' Association Clean and Diversified Energy Initiative.

[12] Mary Johannis (SSG-WI Generation Subgroup Lead) and Tom Carr (WIEB), "Lessons from the 2015 SSG-WI Reference Case", presentation given to the WECC TEPPC, February 12, 2007. Available at http://www.wecc.biz/documents/library/TEPPC/SSGWI_RefCase_Lesson_021207tc.ppt

These slides are included as Appendix C.

(3) What SDG&E would have learned if they had done with a little more validation of their results. Table 2-1 below shows the capacity factors of the generic gas plant additions in Arizona.

TABLE 2-1

Annual Capacity Factors of New Generic Arizona Gas-Fired Capacity Additions, 2015 & 2020
(%)

	2015			2020		
Case:	**200**	**201**	**204**	**200**	**201**	**204**
PV 3-1 (combined cycle)	44%	45%	41%	49%	49%	45%
PV 3-2 (combined cycle)	40%	42%	38%	49%	48%	43%
PV 3-3 (combined cycle)	39%	40%	36%	47%	46%	43%
PV2-1 (combined cycle)	45%	47%	43%	50%	49%	47%
PV 2-2 (combined cycle)	46%	48%	43%	51%	51%	49%
GT-1-1 (simple cycle)	0%	0%	0%	0%	0%	0%
GT1-2 (simple cycle)	0%	0%	0%	0%	0%	0%
GT1-3 (simple cycle)	0%	0%	0%	0%	0%	0%
GT1-4 (simple cycle)	0%	0%	0%	0%	0%	0%

Source: SDG&E response to DRA data request 3-6e.

The results in the table indicate that the generic combined-cycle additions, the most efficient gas-fired plants in their database,[13] with a couple exceptions in 2020, are not even able to breach a 50 percent capacity factor.[14] This type of finding should alert the modeler to the possible existence of a problem.

13 Besides modest amounts of cogeneration additions in such places as Alberta.
14 An annual capacity factor is the ratio of the total generation to the generation that would have been produced if the unit had operated continuously at maximum rating over the year.

The results for the peaker additions are also quite striking – they never operate! This is another significant clue that the resource expansion plan is problematic.[15]

This assumed unreasonable overbuild has a significant impact on SDG&E's modeling results. The CAISO's simulations for LS Power/South Bay Replacement Project (SBRP) shed some light on the importance the resource expansion assumptions.[16] If simply changing the WECC resource expansion to a level that would be required for the market to finance new plant (which I believe LS Power's assumptions represent) increases SBRP Case energy costs to CAISO ratepayers by $732 million, or 7.3%, evidence that WECC resource expansion assumptions are an important driver of ratepayer costs.

Further, it is highly likely that cost differences between a case with Sunrise and without Sunrise would be substantially affected by the WECC regional capacity expansion assumptions. Although no pair of simulations exist to directly answer this question, a review of existing simulations suggest that, under a resource build that is more consistent with investor – and ratepayer – interests, annual energy benefits of Sunrise are likely well under $30 million per year.

2.1.3 Large SCIT Nomogram Congestion Costs Unreasonably Drive up Sunrise Benefits

DRA's review of SDG&E's analysis found that significant congestion costs on the SCIT/EOR Nomogram were apparent – but only in the Sunrise Case.[17] There are several reasons to be alarmed by this finding. The first is methodological. Given the economic benefits methodology, the (positive) difference between the congestion costs resulting

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15 More evidence of a problem could be had from other modeling output, including generator net operating revenues and market prices.

16 See A.06-08-010, *Initial Testimony of the California Independent System Operator*, Part III, April 20, 2007, pp. 56-60.

17 The Southern California Import Transmission (SCIT) Nomogram defines acceptable flow limits on paths delivering power to Southern California. The East of River (EOR) path is one of the major paths limiting Desert Southwest imports into southern California. Increased EOR flows beyond a certain level reduce total Southern California flows (SCIT) as defined by the SCIT/EOR Nomogram.

from the SCIT/EOR Nomogram between the Sunrise Case and the GT Reference Case translates one to one into (positive) CAISO ratepayer benefits (SDG&E assumed that the SCIT/EOR Nomogram is owned 100 percent by CAISO utilities). Table 2-2 below shows SCIT/EOR Nomogram driven Sunrise energy benefits in 2010, 2015 and 2020.

TABLE 2-2

SCIT/EOR Nomogram Congestion and Resulting CAISO Ratepayer Benefits, 2010, 2015 & 2020
(constant 2005$, in millions)

	2010	2015	2020
GT Reference Case (200)	9	16	14
Sunrise Case (201)	51	61	109
Resulting Increase in CAISO Ratepayer Benefit	42	45	95

In other words, increased Sunrise-driven SCIT/EOR Nomogram congestion apparently generates between $42 million (2005$) in 2010 and $95 million (2005$) in 2020 in CAISO ratepayer benefits. The importance of this modeling peculiarity to the Sunrise value proposition is disconcerting, to say the least.

Second, the SCIT Nomogram assumption is a SDG&E modification to the SSG-WI database (the CAISO only models the SCIT limit, not the nomogram). Although brief review of SDG&E SCIT/EOR nomogram modeling assumptions did not uncover any errors,[18] it is possible that a couple otherwise innocent looking SDG&E modifications to SSG-WI assumptions, consisting of an increase to the rating of two lines, both part of the EOR path, by 500 MW each (allowing for a total increase of 1,000 MW in potential EOR flows), has exacerbated this anomalous result.

[18] DRA was not able to complete a full review of SDG&E's nomogram assumptions and results in time for this testimony.

Moreover, the two lines for which SDG&E assumed an increased rating link Southern California to the Four Corners area, which is characterized by some of the most dirty existing coal plants in the country, and in which SDG&E assumed another 3000 MW of new coal plants would be built before 2015. This topic is another example of how important resource build-out assumptions are to SDG&E's Sunrise energy benefit estimates, and why SDG&E's unreasonable assumptions likely significantly skew its modeling results.

2.2 CAISO's Energy Benefits Analysis is Flawed, But a Better Starting Point

Of Sunrise's three apparent important value drivers, two are based on unsupportable assumptions, and a third is a closely related modeling quirk. Unsupportable drivers, as well as significant SDG&E errors, such as double-counting of line losses, are sufficient evidence to conclude that SDG&E's energy benefit estimates are not just exaggerated, but unreasonable and unreliable.

The CAISO's energy benefits modeling process resembles that of SDG&E: it uses the same source SSG-WI database (i.e. prior to custom modifications); it uses the same simulation tool; and it uses the same benefits calculation method. Consequently, many of the same criticisms that apply to SDG&E's modeling also apply to the CAISO's energy benefits analysis, particularly the use of an unsupportable WECC expansion plan. The CAISO, however, includes a better representation of the California transmission system, assumes reasonable gas prices, and avoids SDG&E errors such as transmission loss double-counting and inclusion of energy benefits of non-CAISO entities. For this reason – notwithstanding DRA's belief that the CAISO has also overstated Sunrise, and understated SBRP, benefits – the CAISO's results are a better starting point for analyzing energy benefits.

2.2.1 Whither the Energy Benefits?

DRA generally agrees with the CAISO findings with respect to expected energy benefits:

> "[O]ur cost-effectiveness analysis indicates that although the energy related benefits of Sunrise are probably small, they are still positive …" (pp 6-7, CAISO 3-1-07)

and

> "…given the relatively small level energy benefits, compared to the reliability benefits, the CAISO does not see energy benefits as being the major driver of the Sunrise project" (p. 39, Second Errata to CAISO's 1-3-07 Initial Testimony).

However, there may be other sources of Sunrise benefits that have not been explicitly considered. In particular, uncertainty modeling would likely identify other sources of value for Sunrise – as well as for alternatives to Sunrise. DRA has not made an assessment on the impact that uncertainty would have on Sunrise benefits. However, Mr. Woodruff offers an estimated range of such benefits in Volume 1 of DRA's testimony and also recommends the Commission seek more detailed quantification of this uncertainty as well.

3 AVOIDED RPS COMPLIANCE COSTS

Throughout its application, SDG&E has argued a need for the Sunrise Project in order to meet its RPS requirements in a cost-effective manner.[19] However, it has not demonstrated how Sunrise would allow for RPS compliance in a cost-effective manner. Neither has it demonstrated evidence of the "prohibitively costly congestion,"[20] which it claimed was of a "high likelihood."[21,22]

The CAISO has made important inroads to remedy this shortcoming in SDG&E's application. In Part II of its Initial Testimony, the CAISO developed estimates of the Sunrise RPS compliance related benefits. It developed these estimates from a model that considers a California-wide RPS requirement (demand) and a supply curve based on the costs of procuring renewable energy from various regional (i.e. WECC-wide) alternative renewable resource basins.

As it is reasonable to expect that new transmission out of the Imperial Valley will facilitate renewable development in that area, and that other resources can be procured from elsewhere in the absence of development, then the question is properly one of cost-effectiveness. It is for this reason that DRA appreciates CAISO's contribution in this area. This is not to say the CAISO's RPS compliance cost analysis suffers from any flaws or weakness; rather, it is that, in DRA's opinion, they are just not fatal. The CAISO has introduced a tool that helps shed light on one of the dimensions of the complex decision making problem that the Commission faces in this proceeding.

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19 See for example, "Without substantial new transmission, SDG&E may be challenged to meet its 2010 RPS goals in the most cost-effective manner" (A.05-12-014, "Sunrise Powerlink Transmission Project Purpose and Need, Volume 2 – Part 1, p. III-14) and "…the Sunrise Powerlink is necessary for SDG&E to meet its RPS goals in a cost-effective manner" (*Ibid*, III-15).

20 A.05-12-014, "Sunrise Powerlink Transmission Project Purpose and Need, Volume 2 – Part 1, p. III-15

21 *Ibid*, p. III-15

22 In SDG&E's 2/2/07 Supplemental Testimony Revisions of UCAN Data Request 8-24, SDG&E shows that in 2015, the Sunrise Case decreases the annual marginal cost of transmitting energy from Imperial Valley to San Diego by $1.72/MWh (2005$).

DRA's primary concerns with the CAISO methodology and results follow. First, as acknowledged by the CAISO,[23] there is a large amount of uncertainty concerning the assumptions in the CAISO's RPS compliance cost analysis. Consequently, a good understanding of how sensitive results are to assumption changes is critical. It is further important to acknowledge that the uncertainty underlying the assumptions of this analysis make for results that are "softer" than those of the reliability analysis, but nonetheless still informative and useful for decision making purposes.

Second, crucial to the analysis is that absent Sunrise (or Green Path) new renewables will not develop in Imperial beyond 600 MW, which is presumably tied to the potential upgrade of Path 42 (IID to SCE). However, the CAISO (as well as SDG&E) have assumed that the expansion of Path 42 (IID to SCE) will increase the existing path rating to 1,500 MW (an increase of 900 MW over the existing 600 MW path rating). This suggests that a 600 MW Imperial Valley renewable capacity expansion assumption, absent the development Sunrise or Green Path projects, is low.

Third, as a means of accounting for the uncertainty associated with the development of some of the out-of-state resource clusters, the CAISO reduced available renewable energy from out-of-state areas by 50 percent. DRA does not challenge this assumption at this point, but will point to the fact that eight western states, comprising the large majority of (U.S) WECC load, have a mandatory RPS.[24] This fact underscores the uncertainty that exists with respect to the availability of "low cost" out-of-state resources available to California.

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23 See, for example, "the uncertainty about the ultimate cost of any resource and transmission upgrades included in this analysis is very large" (p.64). See also, "many of the cost estimates we relied on for this analysis are highly speculative, and there are a host of risks that will inevitably prevent some of the resource clusters from being developed at our estimated costs" (p. 66).

24 These states are Arizona, California, Colorado, Montana, Nevada, New Mexico, Oregon, and Washington. Texas also has an RPS, and although the El Paso area of Texas falls within the WECC, DRA did not include it in the count.

Finally, the CAISO has not distinguished – likely due to the absence of good quality data – between CAISO ratepayer interests and other California interests. This failure to distinguish raises a question of consistency between the RPS compliance benefits analysis and those for the energy and reliability benefits.

Based on these findings, DRA developed estimates of a reasonable range of Sunrise related RPS compliance benefits that might be expected from the Sunrise project. These are given in the testimony of Mr. Woodruff in Volume 1.

4 AVOIDED RELIABILITY COST MODELING

DRA also reviewed SDG&E's reliability cost modeling. In his testimony in Volume 1, Mr. Woodruff describes his findings concerning assumptions and approaches taken by SDG&E in its analysis. He also describes alternative scenarios and assumptions that DRA considered in its analysis. In what follows, I briefly summarize DRA's efforts to validate and apply SDG&E's reliability cost model.

4.1 Avoided RMR and CT Fixed Cost Analysis

I reviewed SDG&E modeling and estimates of avoided fixed RMR and CT costs.[25] In each of the cases it explores in its analysis, SDG&E selects a set of units it believes will be needed to meet San Diego reliability requirements. It distinguishes between RMR units receiving Condition 1 and Condition 2 RMR payments. For generators currently under Condition 2 RMR contract, SDG&E assumed historical unit-specific payment information or historical average RMR costs. Condition 1 payments are assumed to be 30 percent of Condition 2 payments. SDG&E assumes that the reliability capacity that does not receive RMR payments will not be available for reliability purposes. However, it assumes that the same capacity will be available in subsequent years once a reliability need arises (e.g. due to load growth). For the period 2021-2049, 2020 RMR fixed payments are assumed to remain constant (on a real dollar basis).[26]

The CAISO, in contrast, completes a "top-down" type analysis, whereby it does not explicitly consider which units are receiving RMR payments. Instead it assumes a ratio of Condition 1 to Condition 2 RMR capacity in 2010 RMR. For the Base Case, all

[25] I use the term RMR recognizing that the Commission and CAISO wish to phase out RMR contracts, and replace them with generator-load serving entity (LSE) Local Capacity Reliability (LCR) contracts. These LCR contracts will continue to have RMR-like provisions, making capacity available to the CAISO for local reliability needs. This is also consistent with SDG&E's use of the term.

[26] In Case 201 (Sunrise), SDG&E assumes some built in escalation between 2021 and 2030. This however, appears to be the exception to the rule.

capacity is assumed to be Condition 2. For the Sunrise Case, based on historical information, it assumes that 21 percent of RMR capacity is Condition 2, the rest consisting of Condition 1 capacity. By the time load growth has exhausted the additional import capability afforded by Sunrise (or other alternative), CAISO assumes that both the Base Case and Sunrise (or other alternative) have the same RMR fixed payments. Costs are then interpolated between 2010 and the year load growth exhaust Sunrise (or other project alternative) additional San Diego import capability.

In my effort to validate estimated avoided fixed RMR costs, I relied principally on SDG&E's fixed RMR cost methodology for the reason that it allowed for more flexibility to test alternative assumptions concerning retirements and alternative payments for RMR provision. I applied a set of assumptions regarding RMR payments and the availability of capacity absent RMR contracts. Mr. Woodruff describes these assumptions in Volume 1. Where existing resources were not available to meet San Diego's reliability need, I assumed CTs would be constructed to meet that need, consistent with SDG&E's assumptions. I estimated a range of avoided fixed RMR costs for a set of alternative assumptions. The results of this analysis are described by Mr. Woodruff in Volume 1.

4.2 Avoided RMR Operating Costs

SDG&E's approach to modeling RMR operating cost savings is very detailed, and considers extreme events. CAISO assumes that RMR operating costs vary directly with RMR contract capacity levels, up to maximum of $60 million per year.

DRA did not make any modifications to SDG&E's "variable RMR cost" analysis aside from testing the impact of certain assumption changes (e.g. the impact of using updated "make-whole payments").

4.3 System RA Costs

Finally, DRA considered the costs of system RA in its analysis. The assumptions concerning system RA are discussed by Mr. Kevin Woodruff in Volume 1. DRA considered several system RA assumptions in its analysis.

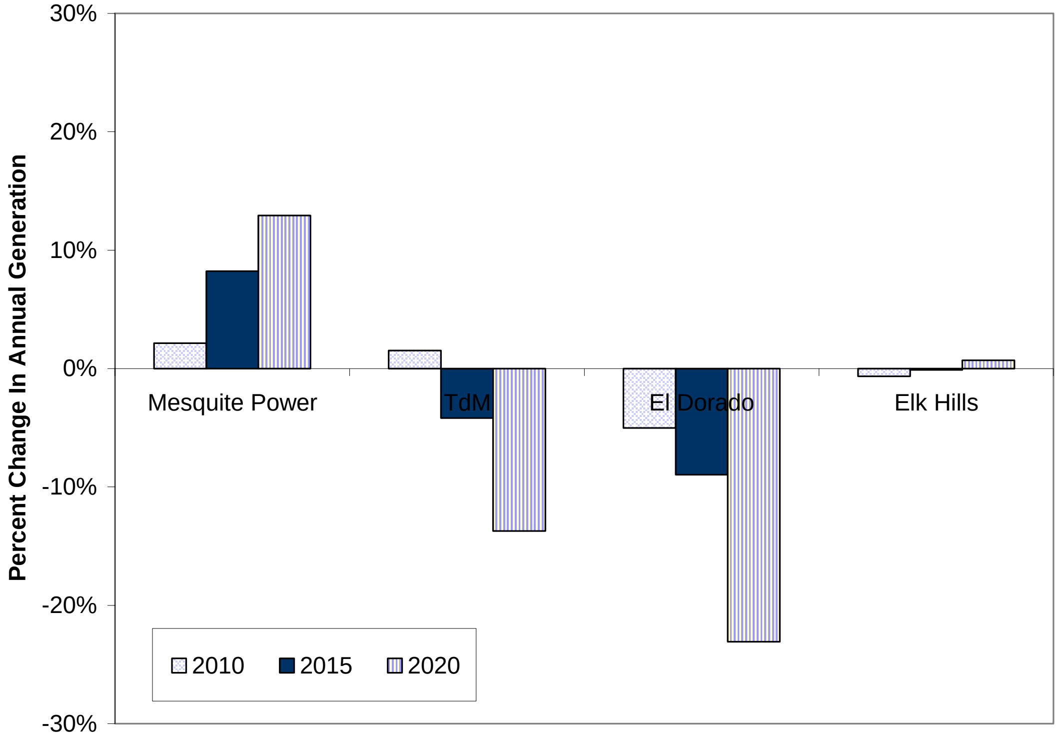
5 SEMPRA MERCHANT GENERATION CONSIDERATIONS

DRA also considered the impact of Sunrise on Sempra Generation's 2,630 MW of generation capacity located in California, Arizona, Nevada and Mexico. SDG&E's modeling shows dispatch from the Sempra Generating portfolio increases 1 percent in the Sunrise Case over the Base Case for 2010 and 2015 and decreases almost 4 percent in 2020. Figure 5-1 shows the same information but on a plant-by-plant basis. The Sempra plant most affected by the Sunrise project would be Termoeléctrica de Mexicali (TdM), which interconnects directly with SDG&E's Imperial Valley Substation. It shows a small increase in generation in 2010, a 2 percent drop in 2015 and a 14 percent decrease in 2020.

However, SDG&E's modeling shows net revenues moving almost in an opposite direction to dispatch, with portfolio net revenues increasing modestly in 2010 and 2015 ($0.35/kW-year and $0.69/kW-year, respectively) and more substantially ($4.46/kW-year) in 2020. Table 5-1 below summarizes these results.

FIGURE 5-1

Sunrise Impact on Sempra Generation Portfolio Plant Dispatch Based on SDG&E Modeling
(%)[27]



27 Based on summer plant ratings.

TABLE 5-1

Net Revenue Impact of Sunrise on Sempra Generation
Based on SDG&E Modeling
(Nominal $/kW-year)[28]

	Mesquite Power	TdM	El Dorado	Elk Hills	Portfolio
2010	-0.68	2.50	1.73	-0.70	0.35
2015	-2.47	8.26	2.67	-1.50	0.69
2020	-1.23	16.15	13.55	-2.38	4.46

[28] Based on summer plant ratings.

APPENDIX A

Daniel Suurkask Qualifications

DANIEL SUURKASK

EMPLOYMENT_HISTORY

WILD ROSE ENERGY SOLUTIONS, INC.
Principal, 2003 - Present

- Assisted, as part of advisory team, major ERCOT market participant prepare for the Nodal Market by means of a systems and process requirements and gap analysis project. Principal role in project consisted of completing assessment of business systems and processes requiring changes for successful participation in nodal market (Needs Assessment).
- Served as expert witness for, and have provided economic and electricity modelling services to, the California Public Utilities Commission's Department of Ratepayer Advocates in the Southern California Edison's Devers to Palo Verde II 500 kV transmission project application (A.05-04-015).
- Provided economic and electricity modelling services to the Nevada Attorney General's Bureau of Consumer Protection in the following Public Utility Commission of Nevada proceedings: Application of Nevada Power Company for Approval of its 2006 Integrated Resource Plan (Docket No. 06-06051); Application of Sierra Pacific Power Company for Approval of 13th Amendment to 2004 Integrated Resource Plan and Energy Supply Update for 2007 (Docket No. 06-07010).
- Market study for wind developer in Alberta. Explored questions relating to market rules and market design, transmission policy and interconnection rules, and environmental attribute value opportunities.
- PJM ancillary services market analysis and 2005-2012 revenue forecast for merchant plant in Virginia.
- Completed 10 year forecast of portfolio dispatch and revenues for merchant power developer with generating facilities in Texas.
- Supporting market analysis for merchant generator negotiating long-term power purchasing agreement with utility in Oklahoma.
- Power market forecast and portfolio analysis to support a utility considering adding nuclear capacity to its portfolio.
- Key participant in comprehensive study of energy policy and electric power industry in Japan, complete with a twenty-year market outlook for the three largest utility regions.
- Risk management framework for Prairie Power, an association of electric co-operatives in Alberta.

Global Energy Decisions, Inc. (Formerly Henwood Energy Services, Inc.)

Project Consultant, Sacramento, CA, 2001-2003

- Numerous fundamental market analyses of WECC, and Eastern Interconnect and various international markets.
- Supporting analysis for over $4.5 billion (USD) in long- and short-term project financings using real options and portfolio risk analysis.
- LMP study of the U.S. Southeast power markets for major energy trading firm.
- Principal contributor to, and resident expert for, the widely subscribed ERCOT advisory service, which includes semi-annual long-term forecasts, expert perspectives on market developments and market design issues, client symposiums and meetings.
- Completed numerous ERCOT portfolio evaluation analyses, amounting to more than 45,000 MW.
- Line loss study in ERCOT, by means of an AC OPF analysis, to assist the client in developing a policy position towards line losses (marginal v. average/pro rata).
- Various contract and call option analyses for Texas clients.
- Scenario-based study exploring "mothballing" and retirement of gas steam units.
- Study of the ERCOT market exploring the revenue potential for "merchant wind" for a wind project developer. Assessed existing market rules and proposed market redesign initiatives as they relate to wind. Evaluated strategies to minimize integration costs and increase value opportunities available to wind.
- Analysis supporting the development of a hedging (Transmission Congestion Rights) strategy against potential transmission congestion charges.
- Multi-client study assessing the viability of new coal-fired generation technology across North America.
- Study examining Mexico-U.S. energy policy in the context of building energy facilities in Mexico and selling into the U.S.
- Review of natural gas market fundamentals, regulatory paradigm, and market dynamics in California.
- Review of natural gas procurement strategies available to the owners of a power plant.
- Market "scoping" exercise for 1 Bcf/day natural gas output for developer of proposed liquefied natural gas regasification facility.
- On-site training for, and support of, new and existing MarketSym and RiskSym software clients.

Canadian Energy Research Institute

Analyst, Calgary, AB, 1997 - 2001

Database Development and Management

- Built, maintained and managed natural gas and electricity databases for analytical studies and modeling purposes.

Major Projects and Studies

- Business opportunities available to a northern Canadian aboriginal band vis-à-vis the oil and gas exploration and development activity.
- Co-authored *Electricity and Gas: Market and Price Convergence*, (with Howard Heintz and Robert Spragins), Calgary: Canadian Energy Research Institute, June 2000.
- Analysis of Alberta's electric transmission tariff and regulatory paradigm; comparative analysis to Colombian transmission pricing paradigm.

EDUCATION

- Master of Arts in Economics, University of Alberta, Edmonton, AB
- Bachelor of Arts (First Class Honors) in Economics, University of Calgary, Calgary, AB

ADDITIONAL_CAPABILITIES

Conventional Applications: Microsoft Office suite products (Word, Excel, Outlook, Access)
Database Management Systems: Access, SQL Server
Programming Languages: Perl, Visual Basic, SQL
Statistical and Mathematical Tools: SHAZAM, Simetar, GAMS, Maple
Power System Simulation: PLEXOS for Power Systems, PROMOD IV, MARKETSYM, Planning and Risk

APPENDIX B

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APPENDIX C

Excerpt from
“Lessons from the 2015 SSG-WI Reference Case”

Seams Steering Group of the Western Interconnection

Lessons from the 2015 SSG-Wi Reference Case

Mary Johannis, SSG-WI
Generation Subgroup Lead
Tom Carr, WIEB

Observations from the trenches

Seams Steering Group of the Western Interconnection

- Need to get the existing generation database right.
- Despite the IRP/RPS guidelines, we added too much generation.
- Need close review of RPS compliance.

Problem of Adding Incremental Generation

Seams Steering Group of the Western Interconnection

- IRP/RPS guidelines provided framework to plan for the future generation additions.
- Aggregate planning margin of 29% suggests we added too much generation.
  - Market would not support/finance excessive capacity
- Difficult to impose fixed planning margin for each region because of import/export patterns.
- Maybe we need an aggregate cap?

2015 Loads and Resources By Area

		2015 Resources		2015 Load			
REGION	AREA	Capacity (1) MW	Discounted Capacity (2) MW	ANNUAL ENERGY MWh	SUMMER PEAK MW (Jul-Aug)	WINTER PEAK MW (Dec-Jan)	Load Coverage within each SSG-Wi Bubble (using discounted capacity)
CALIF ("CAISO")	IMPERIAL	2,108	2,092	4,212,776	1,091	501	92%
CALIF ("CAISO")	LADWP (4)	8,983	8,121	33,314,726	6,249	5,060	30%
CALIF ("CAISO")	MEXICO-C	4,717	4,717	15,278,260	3,209	2,405	47%
CALIF ("CAISO")	PG&E_BAY	7,655	7,274	51,987,840	10,919	10,017	-33%
CALIF ("CAISO")	PG&E_VLY (3)	28,680	27,722	79,993,555	19,549	10,870	42%
CALIF ("CAISO")	SANDIEGO	4,923	4,801	22,962,706	5,058	3,912	-5%
CALIF ("CAISO")	SOCALIF (3)	25,766	22,251	134,936,173	25,462	19,491	-13%
AZNMNV	ARIZONA	30,697	30,697	104,761,526	22,626	14,464	36%
AZNMNV	NEVADA (4)	7,582	7,582	29,345,006	7,276	3,648	4%
AZNMNV	NEW MEXI	5,619	5,427	27,245,822	4,730	4,001	15%
AZNMNV	WAPA L.C	6,389	6,389	1,590,561	252	235	2439%
CANADA	ALBERTA	14,482	13,077	77,291,069	10,362	10,794	26%
CANADA	B.C.HYDR	16,058	13,913	74,158,753	9,248	12,457	50%
NWPP	NW_EAST	36,991	31,402	74,310,368	11,270	12,355	179%
NWPP	NW_WEST	12,508	11,778	107,629,066	15,979	17,913	-26%
RMPP	B HILL	1,120	1,120	6,588,272	972	955	15%
RMPP	BHB	0	0	3,695,185	457	506	-100%
RMPP	BONZ	468	468	1,242,519	237	176	97%
RMPP	COL E	13,979	13,227	62,135,625	10,727	9,521	23%
RMPP	COL W	2,294	2,294	6,440,916	951	993	141%
RMPP	IDAHO	2,575	2,217	18,631,181	3,694	2,850	-40%
RMPP	IPP	1,847	1,847	0	1	1	N/A
RMPP	JB	2,628	2,628	0	1	1	N/A
RMPP	KGB	1,476	952	6,826,263	1,429	1,081	-33%
RMPP	LRS	1,628	1,628	3,996,419	581	567	180%
RMPP	MONTANA	5,579	5,062	10,807,468	1,689	1,698	200%
RMPP	SIERRA	4,137	3,656	11,728,413	1,995	1,642	83%
RMPP	SW WYO	964	321	4,553,805	596	547	-46%
RMPP	UT N	2,438	2,438	42,173,311	7,999	5,368	-70%
RMPP	UT S	3,486	3,486	6,057,463	1,189	819	193%
RMPP	WYO	775	775	2,454,859	331	304	134%
RMPP	YLW TL	288	288	0	1	1	N/A
	Total Capacity	258,838	239,648	1,026,349,907	186,130	155,151	29% (5)