BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U-902) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project.	)))))	Application No. 06-08-010 (Filed August 4, 2006)

ERRATA TO THE REBUTTAL TESTIMONY OF THE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Nancy Saracino
Vice President and General Counsel
Judith B. Sanders
Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
916-351-4400 - office
916-608-7296 – facsimile
jsanders@caiso.com

Dated: July 12, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902 E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project	Application 06-08-010 (Filed August 4, 2006)

ERRATA TO REBUTTAL TESTIMONY SUBMITTED BY THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON JUNE 15, 2007

I. Introduction and Summary

The California Independent System Operator (CAISO) submitted Rebuttal Testimony in this proceeding submitted Rebuttal Testimony on June 15, 2007 and Part V of its Initial Testimony on June 25, 2007. Part V largely consisted of the CAISO analysis of certain alternative scenario combinations requested by the Energy Division (ED) of the Commission's Staff. Several of the combinations involved the TE/VS transmission line portion of the LEAPS project, both on a stand-alone basis and in combination with other projects.

The CAISO's analysis of TE/VS by itself required incorporating the LA Basin RA into the base case. Part V of the CAISO testimony incorporates the LA Basin into the analysis but only for scenarios that showed a net change in the LA Basin. Subsequent to the submission of the Part V testimony, the ED sent a data request to the CAISO asking that the LA Basin RA analysis be extended in the base case and for every alternative studied in part V, even if there is not an impact on the results. The CAISO was also asked to treat LEAPS as a merchant generator and to incorporate AS benefits into the analysis of LEAPS. Finally, the ED data request asked the CAISO to present a summary table of the net benefits of the ED-requested scenarios, as well as the CAISO base case and the three scenarios evaluated in Part II of the CAISO Initial Testimony, using a consistent set of assumptions including the LA Basin RA cost information.

The summary table has been included in an Errata to the Part V testimony. However, in the process of responding to the Staff and developing such consistent assumptions, the CAISO determined that both its Rebuttal testimony and the Part V testimony would have to be revised. Thus, the first four changes set forth below have been made to both the Rebuttal testimony and the Part V testimony in a separate Errata. The fifth description sets forth minor corrections made only in the Rebuttal testimony.

II. Description of Modifications to the Rebuttal Testimony.

The redlined version of the Rebuttal testimony attached hereto contains the following modifications:

- Inclusion of LA Basin reliability costs, to reflect the refined analyses performed for the ED. This includes recognition of the impact of: (1) LCR increases in the LA Basin from reductions in San Diego generation, and (2) LCR reductions allowed by the renewables.
- Refinement of the level of renewable generation in the Imperial Valley under the Green Path scenario. The refinement results in about 74% of the Imperial Valley renewables identified for Sunrise being developed for Green Path.
- Revision of the LEAPS scenario to treat the generator as a merchant plant, rather than a transmission asset. The revision includes removal of the generator costs from the transmission costs and inclusion of a cost-based RMR payment for the generator
- Refine the LEAPS as transmission scenario. The refinement reduces the transmission cost of LEAPS to net out the Ancillary Service and energy benefits of the plant. The refinement also assumes that LEAPS provides RMR capacity at zero cost (any capacity payment would be a transfer from San Diego to all TAC participants).
- Other Corrections

  -Correction of capacity losses for the South Bay repowering case

  -Correction of the $27/kW-yr floor price to be in 2006 dollars instead of 2010 dollars.

-Correct of the calculation of CT costs in the base case to be consistent with the assumption that new CTs continue to receive capacity payments once built. (San Diego LCR declines in 2011. The original analysis held the in-area RMR capacity of existing generators constant and reduced the CT capacity needed in 2011. The corrected analysis holds the CT capacity at the higher 2010 level, and temporarily reduces the amount of existing generation capacity under RMR contracts in 2011)

-Correction of Table 5, SDG&E LCR Table. The original table showed AMI without adjustment for losses. The text descriptions and actual analysis use loss-adjusted AMI, and this is reflected on the new table.

The CAISO will submit a clean copy of the Rebuttal testimony, with the redlined changes accepted, prior to the appearance of the CAISO witnesses on the stand at the evidentiary hearing.

Respectfully submitted,

/s/Judith B. Sander
Judith B. Sanders
Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630

Jeffrey P. Gray
Davis Wright Tremaine LLP
Suite 800
505 Montgomery Street
San Francisco, CA 94111-6533

ATTORNEYS FOR THE CAISO

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U-902) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project.	)))))	Application No. 06-08-010 (Filed August 4, 2006)

REBUTTAL TESTIMONY OF THE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Nancy Saracino
Vice President and General Counsel
Judith B. Sanders
Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
916-351-4400 - office
916-608-7296 – facsimile
jsanders@caiso.com

Dated: June 15, 2007

REBUTTAL TESTIMONY OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
A.06-08-010

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
A.06-08-010

1. Introduction

Q. Please state your names, titles and employer.

A. Our names are Armando J. Perez, Vice President of Planning and Infrastructure Development for the California Independent System Operator (CAISO), Robert Sparks, Lead Regional Transmission Engineer at the CAISO, and Ren Orans, Managing Partner of Energy and Environmental Economics, Inc. (E3). Our qualifications have been previously provided at Attachment A to our initial testimony, Part I, submitted on January 26, 2007.

Q. On whose behalf are you submitting this rebuttal testimony?

A. We are submitting this testimony on behalf of the CAISO.

Q. What is the purpose of this rebuttal testimony?

A. The purpose is to rebut direct testimonies filed by various parties in this proceeding, including (a) Division of Ratepayer Advocates (DRA) of the California Public Utilities Commission (CPUC); (b) Utility Consumers' Action Network (UCAN); (d) The Nevada Hydro Company (TNHC); and (e) South Bay Replacement Project (SBRP).

Q. How is the remainder of this rebuttal testimony organized?

A. Each section below addresses a specific topic brought forth by one or more of the parties. It describes the topic, states the parties' positions, and offers the CAISO's rebuttal.

Section 2 addresses accusations that the CAISO is not fulfilling its role as an independent evaluator. Section 3 addresses issues raised by the parties about the CAISO's economic analysis, encompassing energy benefits, reliability benefits, and renewable portfolio standard (RPS) benefits. Section 4 summarizes the CAISO's opinions on alternatives advanced by the parties, including the deferral cases identified by UCAN and the DRA. Section 5 considers the DRA's proposal for handling uncertainty in Sunrise evaluation. Section 6 presents the CAISO's view of the DRA's proposal of a San Diego Grid Reliability Action Plan (SDGRAP).

2. The CAISO's role as an independent evaluator and the efficacy of its Sunrise studies

Q. Why is this subject being addressed in the CAISO's rebuttal testimony?

A. It is unfortunate that, rather than focus solely on the relevant, important, time-critical and highly complex engineering and economic issues that are at issue in this proceeding, UCAN instead seeks to call into question the CAISO's independence, the efficacy of its study results and its ability to function as a transmission grid planner. The CAISO simply must respond to UCAN's baseless allegations.

Q. How has UCAN called the CAISO's independence into question?

A. UCAN has impugned the CAISO's independence and credibility with many statements sprinkled throughout its testimony. For example, UCAN states that the CAISO's "name turns out to be a bit of a misnomer, in that its actions in relation to STP [Sunrise] don't affirm an image of 'independent'".[1] In discussing the need for an Independent Evaluator for "a re-assessment of the STP [Sunrise] project", UCAN opines that "the unfortunate decision by the ISO to support the STP [Sunrise] project prior to having conducted a meaningful review of the project effectively precludes the ISO from performing this evaluation."[2] With respect to transmission grid planning issues within the CAISO footprint, in particular UCAN's proposed Path 44 upgrade alternative to Sunrise, UCAN queries "what is the ISO's job, if not to integrate the separate grids of its member PTOs into a single seamless statewide grid?"[3]

Finally, UCAN provides a list of reasons why the Commission should "discount" the CAISO's recommendations and study results. While some of these are substantive criticisms that will be addressed in later sections of this testimony, others are simply rhetorical attempts to malign the CAISO's study processes, such as:

- "… the CAISO has a history of crying transmission wolf."[4]
- "…the CAISO's support of STP [Sunrise] appears to have been predetermined."[5]
- "… the CAISO has been reluctant to seriously engage with proponents of alternatives to STP [Sunrise]."[6]

---

[1] *Id.*,.
[2] Marcus, UCAN Testimony on UCAN's Alternatives and Deficiencies of SDG&E and ISO Methodologies - CONFIDENTIAL VERSION (Marcus Confidential), 192.
[3] *Id.*, 39.
[4] *Id.*, 84.
[5] *Id.*, 85
[6] *Id.*

These assertions are unwarranted, inaccurate and an unfortunate distraction from the merits of the proceeding. Once levied, however, they necessitate a response before the CAISO can address the substance of the matter before the Commission.

Q. Has the CAISO's evaluation of Sunrise been conducted independently and in accordance with its statutory mandate?

A. Yes, it has. To begin with, the CAISO is a public benefit corporation created by statute to have no financial or self-interest in the decisions that it makes. In addition, the CAISO's role is to make recommendations that best serve the citizens of California, and to provide and explain its support for those recommendations. During the course of this proceeding, the CAISO conducted many model runs taking into account specifications directed by the interveners, including UCAN, for whom the CAISO ran multiple model runs to UCAN's exact specifications[7]. Indeed, UCAN glosses over the many instances during the course of this proceeding in which the CAISO agreed with UCAN's comments and assumptions and changed its own models accordingly. UCAN instead chooses to focus on the CSRTP 2006 study process and criticizes the conclusions reached by that group which are inconsistent with the UCAN alternatives. UCAN then jumps to the conclusion that the CAISO's study results were pre-ordained and that once the CAISO's Board of Governors (Board) approved Sunrise, the CAISO has had no choice but to continue to support the project.[8] This conclusion is contradicted by the facts. It is appropriate and expected that the CAISO

[7] A case in point is the 12 runs reported in The CAISO Initial Testimony, Part III, April 20, 2007
[8] *Id.*, 85-86.

continue to refine and examine assumptions and models as circumstances change. In this case, the CAISO's continued studies and assessments supported the conclusions reached in the initial report. At all times, the CAISO maintained its appropriate role of an independent and neutral technical analyst.

Q. Do you agree with UCAN's assessment of the CSRTP group recommendations?

A. No, we do not. UCAN's implication that the CAISO and the CSRTP study group came to a predetermined conclusion simply is not correct. What is true is that the group was tasked with conducting its analysis of Sunrise under very tight time constraints, given that the timeframe for the project was dictated by the need for it to be constructed by a certain date, and that the project proponents needed a certain amount of time to seek regulatory approvals and ultimately complete the project.[9] For expediency purposes, the CSRTP group made use of studies that had already been completed, including alternatives to the project. [10]

Q. Did the Board's approval in August, 2006, preordain the CAISO's unequivocal support for Sunrise in this proceeding?

A. No, and that should be apparent from the CAISO testimony filed in this proceeding. First, however, we would note that the CAISO Board, in approving CAISO management's recommendation that a transmission project be approved, understands that the project will be subject to regulatory scrutiny and could be

[9] As described in the Report, the CSRTP group was formed to study the LEAPS and Tehachapi projects as well as Sunrise (Report, 16). The enormous amount of work involved in studying three large transmission/pumped hydro projects simultaneously has apparently led to UCAN's conclusions that its alternatives, proposed in April, 2006 and not studied until two months later, were "ignored". (Marcus, 85)
[10] CSRTP 2006 Report, July 28, 2006, 16.

altered during the CPUC approval process. Indeed, it has happened in the past that CAISO management has come back to the Board for approval of project changes.

Furthermore, as an active participant in this proceeding, the CAISO has, since January 2007, filed testimony regarding the changes in its cost-benefit calculation, input data assumptions, and cost-effectiveness results with respect to the Sunrise project that are quite different from those described in the CSRTP Report. The CAISO has also performed extensive analyses requested by interveners, and, as noted above, has made corrections and changes to its own analyses based on input from the interveners at the testimony workshops. All this work was directed by a team of CAISO staff and consultants that were not involved with the CSRTP Report, nor did the team collaborate with any CSRTP group participants in developing the conclusions set forth in its testimony.

Q. **Does the CAISO's support of the Sunrise project disqualify it from being an independent evaluator of future proposed transmission projects and the statewide transmission planner?**

A. It goes without saying that the CAISO is *mandated* by Section 345 of the Public Utilities Code to "ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by NERC and WECC. This mandate has been carried out in the past through numerous transmission planning studies conducted by the CAISO and in conjunction with stakeholder and industry groups. Studies for expanded transmission planning for southern California and the regional southwest have been continuously evaluated by the CAISO and interested participants and have been the subject of sub-regional planning groups since the formation of the Southwest Transmission Expansion Plan (STEP) group in 2002.[11] Indeed, the STEP group examined alternatives to Sunrise prototypes, as well as considering the LEAPS combined transmission and generation project.[12]

Looking to the future, in January, 2007 the CAISO posted its 2007 Long Term Transmission Plan (Plan), the first annual transmission planning report in a process initiated in 2005 to transform the role of the CAISO to achieve a more proactive transmission planning role that will benefit all of the citizens of California.[13] The CAISO's Plan is driven by the ongoing effort to facilitate the development of an overall Integrated Planning Process. As expressed in the Plan, the CAISO has concluded that the preparation of a single, integrated transmission plan that describes for all stakeholders how the CAISO and PTOs are coordinating to assure that the CAISO Controlled Grid is being upgraded in an efficient and economical way. This proactive statewide planning will include a robust and open stakeholder process with transparent study assumptions made available to all participants. Whatever shortcomings UCAN believes were inherent in the CSRTP process should be dispelled with the current transmission planning protocols that the CAISO is putting in place.

[11] The CSRTP group was formed under the umbrella of the STEP group.
[12] The planning studies and other STEP materials can be found at http://www.caiso.com/docs/2002/11/04/2002110417450022131.html
[13] The 2007 Long Term Transmission Plan can be found at http://www.caiso.com/1b6b/1b6bb4d51db0.pdf

Q. Does the CAISO have "a history of crying transmission wolf"?[14]

A. UCAN has not clearly expressed its basis for this allegation. However, the CAISO assumes that this phrase refers to the Commission's denial of SDG&E's request for a CPCN for the Valley-Rainbow transmission project (A. 01-03-036) and the fact that the CAISO found that Valley-Rainbow was needed for reliability purposes. Apparently because the lights didn't go out go following the denial of the CPCN, UCAN implicitly has concluded that the CAISO has a tendency to approve proposed transmission projects that are not really needed.

UCAN's conclusions in this regard are misplaced. The determination of need for any facility is based exclusively on compliance with national and western reliability standards, which starting this month, are mandatory and carry penalties. Just like the analysis conducted in this proceeding for Sunrise, the CAISO evaluated the Valley-Rainbow project in accordance with its planning standards that call for a G-1/N-1 assessment to determine reliability needs. That analysis supported a need for the project beginning in 2006.[15] The fact that the Commission disagreed with the CAISO's needs analysis—and the G-1/N-1 contingences did not come to pass so that load shedding conditions did not occur—does not mean that the CAISO's planning and forecasting was flawed. Furthermore, major transmission projects such as Valley Rainbow or Sunrise are long term solutions to conditions that, over time, will eventually lead to reliability concerns. It is certainly short-sighted to dwell in the recent past or focus on short-

[14] Marcus, 84.
[15] Waite, Testimony of The Nevada Hydro Company (TNHC) (Waite), Exhibit No. 5, at 9.

term transmission “fixes” when decisions that are made today could impact future generations. There is no disagreement that the San Diego area is transmission-constrained, and the CAISO’s vision for development of a robust transmission infrastructure in no way constitutes “crying wolf”.

3. Economic analysis

3.1 Energy benefit estimation

Q. What are the parties’ positions regarding the CAISO’s estimation of energy benefits for the base case and alternatives?

A. The positions are as follows:

- Different dispatch model. TNHC uses PLEXOS, not Gridview, to quantify energy benefits of the TE/VS line.[16] SBRP uses a transportation model, claiming that it is superior to power transmission distribution factor (PTDF) models such as Gridview and PLEXOS.[17]
- Production cost difference as total economic benefit. SBRP opines that the production cost change in the WECC is the total benefit of a project.[18] Based on its analysis, SBRP concludes that “it is more cost effective to build generation in the San Diego zone than it is to build remote generation and build transmission to access the remote generation.”[19]

---

[16] Zhang, Phase 1 Testimony on Behalf of The Nevada Hydro Company, June 1, 2007 (Zhang).
[17] Lauckhart, Prepared Testimony on Behalf of South Bay Replacement Project LLC, June 1, 2007, at 11 and 17 to 18.
[18] *Id.*, Appendix 4.
[19] *Id.*, 19.

- Producer surplus computation. SBRP states that "SDG&E and CAISO should be identifying resources that have a total MW capacity equal to the CAISO 15% PRM when choosing their resources." [20]
- Accuracy of the SSG-WI database. The DRA opines that the database has excessive generation, as evidenced by the 29% planning reserve margin and the projected capacity utilization of under 50% for the combined cycle gas turbines (CCGTs).[21] SBRP shares this view,[22] remarking that "[t]he amount of generation included in the database used by SDG&E and CAISO is so excessive that any runs they made with this database (which is essentially all their runs) would not provide credible results." [23]
- Lower energy benefit estimate for Sunrise. The DRA's $25M base case estimate for Sunrise is $10M lower than the CAISO's $35M estimate. The DRA rationalizes its lower estimate with its claim of "the infirmities that plague the CAISO energy modeling."[24]
- Energy benefit for the Talega-Escondido/Valley-Serrano (TE/VS) project. TNHC's estimate of the project's energy benefit in 2015 is $14M/year.[25]

---

[20] *Id.*, 16.
[21] Suurkask, D. Report on The Sunrise Powerlink, Phase 1 Direct Testimony, Volume 3 of 5, DRA, CPUC, May 18, 2007, 6 (Suurkask).
[22] Lauckhart, Prepared Testimony on Behalf of South Bay Replacement Project LLC, June 1, 2007, 13(Lauckhart).
[23] *Id.*, 15.
[24] Woodruff, K. Report on The Sunrise Powerlink, Phase 1 Direct Testimony, Volume 1 of 5, DRA, CPUC, May 18, 2007, 37 (Woodruff).
[25] Auclair, P. Phase 1 Testimony on Behalf of The Nevada Hydro Company, June 1, 2007, 31 (Auclair).

A. Different dispatch model

Q. Is SBRP correct that PTDF-based approaches, such as Gridview and PLEXOS, have not been demonstrated to be reasonable or valid?

A. No. In fact, it is generally accepted among power engineers that PTDF models are more accurate than transportation models (e.g., the model used by SBRP in this proceeding) which completely ignore the laws of physics. Both Gridview and PLEXOS are PTDF models that have been accepted by the CAISO and the Commission in the application of the CAISO's TEAM methodology.

To be sure, there have been questions about specific aspects of Gridview related to the calculation of ancillary service costs, the dispatch of pumped storage units, and its sensitivity to assumptions and input data. However, those questions similarly apply to a transportation model and they in no way invalidate the CAISO's use of Gridview to estimate a transmission project's energy benefits.

Q. Does the CAISO believe that THNC's analysis is flawed because THNC uses PLEXOS instead of Gridview?

A. No. The CAISO believes that PLEXOS can produce reasonable and reliable results, as evidenced by the CAISO's own use of PLEXOS in other venues. The CAISO concurs with TNHC that differences in results would most likely be driven by differences in modeling assumptions, not differences in models.[26]

[26] Zhang, 11.

B. Production cost difference as total economic benefit

Q. **Is SBRP correct that the total benefit of a transmission project can be estimated using only the change in production costs?**

A. No. The CAISO's TEAM methodology focuses on the economics of a project for CAISO customers. SBRP formulation of net benefits would be correct *only* if the focus is the entire WECC. In light of SBRP's misspecification of net benefits, the CAISO doubts SBRP's conclusion that building local generation in San Diego is more cost-effective than a transmission alternative such as Sunrise.

C. Producer surplus computation

Q. **Is SBRP correct that producer surplus should include enough resources to equal utility demand plus their 15% planning reserve margins?**

A. No. The producer surplus adjustment is used to reflect how utility profits from utility owned generation flow to the CAISO's customers through retail ratemaking. Because profits to non-utility owned generation do not flow to the CAISO's customers, it is incorrect to include the producer surplus for those generators as a net benefit under the TEAM methodology.

D. Accuracy of SSG-WI Database

Q. **Does the CAISO believe that the high resource levels from the SSG-WI database lead to results that are not credible?**

A. No. The TEAM methodology evaluates how consumer costs *change* with the addition of a project. The same SSG-WI resources are used in both the base case and its alternatives. The presence of alleged excess generation would not necessarily bias our analysis towards Sunrise.

To see this point, consider the CAISO estimate of Sunrise's energy benefits, which are mainly driven by the differentials in nodal prices under locational marginal pricing (LMP). The LMP price differentials are attributable to differences in marginal fuel costs and marginal line losses by location. As long as the marginal generation units within and outside California are similar natural-gas-fired units and the locational natural gas price difference is small, the excess generation levels in the SSG-WI database should not have a material effect on the CAISO's energy benefit estimate.

Q. Is it likely that excess generation in the Southwest created additional benefits for Sunrise?

A. There is a possibility that excess generation in the SSG-WI database creates small increases in Sunrise benefits. We believe that any bias in favor of Sunrise is small for two reasons. First, our own analysis indicates that the benefits are very sensitive to assumed regional differences in gas prices implying that for many hours of the year, gas fired generation resources are setting the market prices both inside and outside of California. Non-gas fired resources in general, whether they are excess or being dispatched, seem to have a second order impact on market prices and the economic evaluation of Sunrise benefits. Second, the Sunrise line in the CAISO's Sunrise case is extensively used by renewable resources. Since these resources have low variable costs, they are dispatched before other resources, thus mitigating the impact of any excess resources on market prices in California.

E. Lower estimate for Sunrise

Q. What is the CAISO's opinion on the DRA's $25M base estimate?

A. The DRA arbitrarily lowers the CAISO's $35M estimate, without any empirical evidence that the $10M reduction is justified by a correct modeling effort (e.g., a Gridview run) that remedies the alleged "infirmities that plague the CAISO energy modeling."[27] Hence, the CAISO rejects the DRA's estimate by reason of lack of evidence.

F. Energy benefit for TE/VS

Q. What is the CAISO's opinion on TNHC's estimate of the TE/VS project's $14M/year estimate of energy benefit?[28]

A. The CAISO has not performed an analysis of TE/VS as a stand-alone project. Hence, it can only note that THNC's $14M/year estimate for TE/VS is comparable to the CAISO's $10M/year estimate for (Green Path + LEAPS).[29]

3.2 Reliability benefit estimation

Q. What are the parties' positions regarding the CAISO's estimation of reliability benefits?

A. The positions are as follows:

[27] Woodruff, 37
[28] Auclair, 31
[29] Second Errata to Initial Testimony of The California Independent System Operator Corporation, Part II, Application 06-08-010, April 20, 2007, 6.

- Resource adequacy (RA) cost. UCAN states that the RA cost floor should be $27/kW-year, instead of the fixed O&M costs of $10.72/kW-year used by the CAISO.[30]
- Replacement RA costs. UCAN argues that (a) if local RA is reduced by Sunrise, then non-local RA requirements would have to increase by the same amount; and (b) these additional system RA costs should be attributed to Sunrise.[31]
- Lower benefit estimate for Sunrise. The DRA's $66.4M estimate is $82.6M lower than the CAISO's $149M estimate (Second Errata to Initial Testimony, Part II). The DRA justifies its lower estimate based on its assessment of San Diego's LCR need *sans* Sunrise, which indicates no capacity deficiency until 2015.[32]
- Reliability benefit of TE/VS. TNHC's estimate of the TV/ES project's reliability benefit is twice of the CAISO's $63M/year in 2015 for (Green Path + LEAPS) because of their assumption that the TE/VS line increases import capability into San Diego by 1,000 MW, rather than the 500 MW estimated by the CAISO.[33]

---

[30] Marcus Confidential, ,70
[31] Marcus Confidential , 69.
[32] Woodruff, Table ES-1.
[33] Auclair, 31; Depenbrock, Phase 1 Testimony on Behalf of The Nevada Hydro Company, June 1, 2007, 9 (Depenbrock).

- Fixed cost component of remote generation. THNC claims that the CAISO has not included the fixed cost component of remote generation SDG&E would rely on if Sunrise were built.[34]
- Mix of renewable resources throughout the West. THNC claims that the CAISO testimony itself undercuts the preference for Imperial Valley resources by making the unrealistic assumption that all identified renewable resources throughout the West include the same mix of geothermal, wind and solar resources.[35]

A. Resource adequacy (RA) costs

Q. Does the CAISO accept UCAN's suggestion of using $27/kW-yr (in 2006 dollars) as the floor for RA payments?[36]

A. Yes. The higher floor value reduces the total levelized net benefits of the CAISO Sunrise case by $7~~6~~ million (from $103~~84~~ million per year[36B] to $96~~78~~ million per year). Table 1 below shows the levelized costs and benefits of each alternative using this new floor value for RA, as well as UCAN's recommended 8.23% discount rate.~~.~~

[34] Auclair, 21.
[35] *Id.*, 19.
[36] Marcus Confidential, 81.
[36B] The 103 million per year incorporates changes for the reliability costs in the LA Basin, and an 8.23% discount rate. In this way, the impact of the $27/kW-yr floor price can be isolated.

Table 1: Levelized costs and benefits by alternative under the $27/kW-year RA price floor.

		A	B	C	D	E	F	G
	Summary of Levelized Costs and Benefits	**Costs** ($ millions per year, nominal)				**Net Benefits** (Base case cost - Alt. case cost)		
		Base Case - San Diego & LA	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,736	15,615	15,684	15,694	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(123)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,744)	(4,710)	(4,719)	(4,735)	(34)	(24)	(9)
4	Less IOU excess loss payments	(808)	(792)	(802)	(799)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,061	10,026	10,060	10,051	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	312	293	346	326	19	(34)	(14)
7	RMR Operating Payments - Levelized	60	48	60	58	12	-	2
8	CT Capacity Costs - Levelized	364	267	306	269	96	57	95
9	Transmission cost for new CTs-Levelized	128	94	108	95	34	20	33
10	Remediation cost to provide reactive support	-	-	-		-	-	-
11	System RA Provided by local capacity & RPS	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	864	703	820	748	**161**	**44**	**116**
13	**Total Energy and Reliability Benefits**					**197**	**44**	**126**
	RPS Procurement Cost							
14	Adjusted RPS Cost	5,312	5,256	5,312	5,270	56	-	41
15	**Total Benefits**					**253**	**44**	**168**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	8.5	97.0	(157)	(8.5)	(97.0)
17	**Total Costs and Benefits**	16,237	16,141	16,201	16,166	**96**	**36**	**71**

		A	B	C	D	E	F	G
	Summary of Levelized Costs and Benefits	**Costs**				**Net Benefits**		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,750	15,629	15,697	15,708	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(124)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,748)	(4,714)	(4,724)	(4,739)	(34)	(24)	(9)
4	Less IOU excess loss payments	(809)	(793)	(803)	(800)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,070	10,035	10,069	10,060	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	90	66	125	86	24	(35)	4
7	RMR Operating Payments - Levelized	60	48	60	58	12	-	2
8	CT Capacity Costs - Levelized	110	31	56	61	79	54	49
9	Transmission cost for new CTs-Levelized	39	11	20	21	28	19	17
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	299	155	261	227	**143**	**37**	**72**
13	**Total Energy and Reliability Benefits**					**179**	**38**	**82**
	RPS Procurement Cost							
14	Adjusted RPS Cost	5,320	5,264	5,320	5,264	**56**	**-**	**55**
15	**Total Benefits**					**235**	**38**	**138**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	9.3	205.2	**(157.0)**	**(9.3)**	**(205.2)**
17	**Total Costs and Benefits**	15,688	15,610	15,660	15,756	**78**	**29**	**(67)**

Q. What other modifications has the CAISO incorporated into Table 1?

A. The CAISO has made the following changes:

1. Added the reliability cost/benefit impact on the LA basin to the existing analysis of the San Diego area.

2. Revised the RPS procurement costs and benefits for the (Green Path + LEAPS) case to reflect the fact that only 2000Mwsof renewable resources could be delivered from the Imperial Valley in Green Path North case. Our reliability analysis supports this assumption.
3. Revised the economic treatment of LEAPS to reflect the plant as a merchant generator, rather than as a transmission asset. This is consistent with the CAISO's FERC position on the treatment of the LEAPS as a merchant generator and is responsive to THNC's arguments that TE/VS should be compared to Sunrise rather than the bundled package of TE/VS, LEAPS generation and Green Path North.

Q. Why has the CAISO included the LA Basin in the new results tables?

A. The CAISO's analysis of the TE/VS component of the (Green Path + LEAPS) project in Part V or our testimony explains how this project would decrease the Local Capacity Requirements (LCR) in San Diego by 500MW, and that reducing 500MW of generation in San Diego, increases the LCR in the LA Basin by 500MW. In order to facilitate comparison of the alternative scenarios, the CAISO has revised its cost and benefit calculations for the Sunrise, (Green Path + LEAPS) and South Bay cases to include the LA Basin reliability costs in both the base case and alternative cases for Sunrise, (Green Path + LEAPS) and South Bay. This change requires a modification to the base case to include the local capacity costs of the LA Basin . The benefits of the Sunrise, (Green Path + LEAPS) and South Bay cases, under this updated framework, are the costs of the new "Base Case SD & LA Basin" case less the costs of the alternative case.

Q. How has the CAISO estimated the costs related to the 500 MW increase in the LA LCR in this case?

A. The 500MW increase in the LA LCR has been included in the analysis through two effects: (1) an increase in LA RMR requirements that increases RMR prices in the LA basin until all local non-IOU generation is utilized, and (2) an increase in the quantity of local RMR that must be contracted, subject to the existing amount of non-IOU generation in the LA basin.

Q. What did the CAISO use for LCR in the LA Basin?

A. Table 2 below shows the CAISO's estimate of LCR for the LA Basin in the base case through 2020. After 2020, LCR is increased using the trend from 2016 through 2020. The LCR excludes IOU generation. The base case uncommitted, non-IOU owned RMR capability is 4530MW.

Table 2: Base Case LCR (MW) between 2010 and 2020 for the LA Basin

Year	Base Case LCR (Non-IOU) (MW)
2010	2,069
2011	2,449
2012	2,829
2013	3,209
2014	3,589
2015	3,969
2016	4,349
2017	4,729
2018	5,109
2019	5,489
2020	5,869

Q. Do renewable resources delivered from the Imperial Valley affect the LA LCR?

A. Yes, there are reliability related benefits from renewable resources in both our Base Case and in the Sunrise and Green Path North cases. For example, in our Base Case the CAISO estimates that approximately 700MW of renewable resources could be developed in the Imperial Valley without any major transmission upgrades. The 700MW of generation from renewable resources would offset approximately 525MW of local capacity requirements in the LA Basin. Since the capacity provided would be an additional byproduct of the renewable energy contracts, the renewable energy procurement process can be expected to reduce LA's LCR requirements by 525 MW and provide associated benefits in the base case.

In the Sunrise case the CAISO estimates that the combination of the new transmission line and the total of 2700MW (2000 of incremental above the Base Case) of renewable resources provides two reliability benefits. First the project will increase the San Diego area's import capability by 1000 MW, thereby reducing San Diego's LCR requirements. Second, it will also provide approximately a 298 MW reduction in LCR requirements in the LA Basin by 2015 above the 525MW already provided in the Base Case.

Q. How was the LA Basin decrease in LCR requirements calculated in the Sunrise case?

A. Table 2B shows that renewable resources in the Sunrise case have the ability to decrease the LCR requirements in the LA Basin by 1823MW.[37] Of this, 525MW could be provided under the base case (no Sunrise or Green Path) so the net impact of Sunrise is the ability to reduce LA LCR by 1298MW. Sunrise would also allow for the reduction of 1000 MW of LCR in the San Diego area which would increase LA's LCR requirements by 1000 MW. Therefore, in the Sunrise case, the net LCR reduction to the LA Basin by 2015 is only 298 MW (1298MW – 1000MW).

Table 2B: LA LCR Reductions from Imperial Valley Renewables

		A	*B*	*C*	*D*	*E*
		LA LCR reductions from renewables in Imperial Valley (MW)			Increment relative to Base Case (MW)	
	Year	Base Case	Sunrise	Green Path	Sunrise	Green Path
1	2010	525	525	525	-	-
2	2015	525	1,823	1,350	1,298	825

Q. Does the inclusion of the LA Basin in your analysis have an impact on the reliability benefits of the (Green Path + Leaps) case?

A. Yes. In the (Green Path + LEAPS) case, the CAISO analysis indicates that approximately 2000MW of renewable generation could be reliably interconnected and delivered over the Green Path North transmission line. This level of renewable resources translates into a reduction in the LA basin LCR by 1350MW by 2015, of which 825MW is incremental to the base case. As discussed below, the CAISO analysis also indicates that this option produces a reduction of 500 MW of LCR in the San Diego area in the (Green Path + LEAPS) case. The

[37] IID resources are approximately 75 percent effective in reducing LA Basin LCR. 75% is applied to the renewable capacity from the Imperial Valley that would qualify for system RA. This analysis assumes 1800MW of geothermal resources that are counted 100% toward RA and 900MW of solar resources that are counted 70% toward RA.

decrease in the San Diego area LCR requirements has a corresponding impact of increasing the LA Basin LCR by 500 MW. Therefore, in the (Green Path + LEAPS) case, the net LCR reduction to the LA Basin by 2015 is 325MW (825-500) MW.

Q. Why is the amount of renewables lower in the (Green path + LEAPS) case than the Sunrise case?

A. Based on transient stability analyses, the CAISO has determined that (Green Path + LEAPS) could not deliver the full 2700MW of renewables from the Imperial Valley. After reviewing those detailed study results the CAISO has determined that 2000MW is the CAISO's best estimate of the maximum amount of renewables that could be reliably interconnected and delivered with (Green Path + LEAPS).

Q. Renewable development in the Imperial Valley reduces the LA LCR in the Sunrise and (Green Path + LEAPS) cases by 1298MW and 825MW relative to the base case in 2015. Does the renewable development reduce RA requirements relative to the base case by a similar amount?

A. No. For system RA, capacity needs only to be deliverable to the California grid to be counted for RA. Therefore the renewable resources developed in areas other than Imperial Valley in the base case can be counted for RA. The renewable mix in the Imperial Valley does provide a relatively high amount of RA because of its relatively high proportion of geothermal resources and low proportion of wind resources. The differential RA provided between the Sunrise and Base Case, however, is only 340MW at most.

Q. How has the CAISO estimated the benefits related to the 500 MW decrease in the San Diego LCR for the (Green Path + LEAPS) case?

A. The 500MW decrease in the San Diego LCR decreases the RMR prices and quantity of RMR needed in San Diego and decreases the need for future capacity provided by CT's..

Q. Has the CAISO changed its estimate of the levelized cost of (Green Path + LEAPS)?

A. Yes. The CAISO has updated the cost of the transmission component of the LEAPS project using an updated Valley Rainbow estimate provided by SDG&E in response to CAISO data request 1. The CAISO has also excluded the cost of the advanced pumped storage generator to make the cost consistent with the CAISO position that the pumped storage unit should not be a transmission asset. This results in an $8.7M reduction in levelized costs, which reduces the cost of (Green path + LEAPS) from $205.2M to $96.5M per year.

Q. Does treating LEAPS as a merchant plant require any other cost adjustments?

A. Yes. The CAISO has estimated that the cost of the LEAPS advanced pumped storage plant would be above the cost of RMR payments to existing generators, even after crediting the pumped storage generation with ancillary service and energy payments. The CAISO therefore believes that it would be unrealistic to assume that pumped storage capacity could be purchased at the RMR price levels in LA. The CAISO estimates that a contract with the pumped storage plant would cost approximately $51.30/kW-yr in 2010 dollars and escalate at 2% per year[38]. This value is the cost of the pumped storage less the revenues the plant would receive from ancillary services and energy payments. In other words, $51.30/kW-yr is the "make whole" payment needed to be paid to the generator, after it receives revenues from selling its energy and Ancillary Services into CAISO markets. The CAISO's estimation of AS and energy revenues is discussed further in Section 7 of this rebuttal testimony. The CAISO has therefore increased the RMR payments for the pumped storage to equal $51.30/kW-yr (2010 dollars).

Q. **Has the CAISO included LA Basin reliability costs for the Sunrise case for both 2010 and 2015?**

A. Yes, the CAISO has modeled the Sunrise transmission line implemented by itself in 2010 as reducing LCR in San Diego by 1000MW and increasing LCR in LA by 1000MW. In the early years, prior to the full development of renewable resources in the Imperial Valley area, this increase in LA LCR is a negative benefit to the Sunrise case. Eventually, however, the 1000MW LCR increase in LA is more than covered by the incremental RMR capacity provided by the Imperial Valley renewable generation (1298 MW of incremental RMR capacity by 2015). Overall, the inclusion of the LA basin reliability costs increased the CAISO's estimates of Sunrise levelized net benefits by between $16M to $18M, depending upon the other case assumptions.

[38] This is based on the FERC Filing 2005 cost estimate of $1283 M less $350M for TEVS. The CAISO escalated the remaining $933 million for the pumped storage by 2% per year to convert to 2010 dollars, and applied the same 1.45 revenue requirement adjustment that was used in the CAISO's April 20, 2007 filing. This $1474M revenue requirement was then levelized over 41 years using a 6.1 % real discount rate to derive an annual cost of $99.9M/yr in 2010 dollars that escalates annually at 2%. Subtracting AS and RA benefits of $74.3M/yr, and dividing by 500MW yields the pumped storage net cost of $51.3/kW-yr.

Q. Did the CAISO also include LA Basin reliability costs in the South Bay Repowering case?

A. Yes, it has, even though the South Bay Repowering Case does not provide net benefits to the LA Basin. The CAISO has modeled the South Bay case as not affecting the LA Basin LCR, so there would be no reliability cost change for the LA Basin However, for consistency with the changes needed for the (Green Path + LEAPS) and Sunrise cases, the CAISO has included the reliability costs of LA Basin in the South Bay case. Since the LA Basin RA costs are also included in the Base Case, this change has no impact on the net benefits calculated for the South Bay case.

Q. Why have the reliability benefits increased for the South Bay case?

A. The CAISO found an error in the treatment of capacity losses in the South Bay case. Correcting the losses error increases the South Bay levelized net benefits by approximately $6M.

B. Non-Local RA costs

Q. UCAN also argues that reducing local RA obligations by 1000 MW would increase non-local RA obligations by 1000 MW.[39] Does this mean that SDG&E would have to procure an additional 1000MW of non-local RA once Sunrise is in service?

A. The CAISO accepts UCAN's argument that reducing local RA obligations by 1000 MW would increase non-local RA obligations; and it adjusts its estimate of

[39] Marcus Confidential, , 79.

the Sunrise benefits accordingly. Because some of the non-local RA is provided by the renewable resources in the Sunrise case, the CAISO estimates that 660 MW is the net increase in non-local RA requirement.

The amount of additional non-local RA that SDG&E would need to purchase is affected by the amount of RA provided by the RPS purchases in the base and Sunrise cases. If the Sunrise RPS mix provides more RA-qualified capacity than the renewable resources added to the base case, then this additional capacity should be netted against the 1000 MW of RA that would need to be procured. RPS resources provide RA capacity because the CAISO models RPS purchases at the full cost of the renewable resource, including return on and of capital investments. Accordingly, these payments are for both the energy and capacity output from the renewable resources.

Based on the current RA counting rules, which count RA capacity as the average produced over the summer on-peak hours, the CAISO has assumed that 100% of geothermal capacity, 70% of solar thermal capacity, and 20% of the installed wind capacity are RA-qualified. Table 2 below shows the amount of RA-qualified capacity in the base case RPS resource mix and the Sunrise RPS resource mix. The table shows that the Sunrise mix provides 340MW more RA-qualified capacity than the base case. Thus, the Sunrise case would require purchases of no more than 660MW of non-local RA capacity, not 1000MW as UCAN asserts. Note that for the TEAM methodology it does not matter how much of the renewable output is purchased by SDG&E. It is reasonable to assume that the increase in RA-qualified capacity would flow to a CAISO participant either through direct purchase of the renewable energy or through secondary purchase of the RA capacity.

Table 2: Non-Local RA Difference between Base and Sunrise Case

	Installed MW			RA Qualifying MW	
	Base	Sunrise	RA %	Base	Sunrise
Geo	1190	1000	100%	1190	1000
Wind	500		20%	100	0
Solar		900	70%	0	630
Total	1690	1900		1290	1630
RA Difference					340

Q. Have you estimated the impact of the 660MW of non-local RA capacity on your estimates of net benefits for each alternative?

A. Yes. Based on UCAN's non-local RA value of $27 kW-year in 2006 dollars, Table 3 below shows the levelized annual benefits of Sunrise are reduced by another $29M~~26M~~/year. This brings the annual net benefits for Sunrise down to 67M~~52M~~/year.

Table 3: Levelized costs and benefits by alternative assuming both Supplemental Non-Local Capacity Purchases and the $27/kW-year RA price floor.

	Summary of Levelized Costs and Benefits	A	B	C	D	E	F	G
		Costs ($ millions per year, nominal)				Net Benefits (Base case cost - Alt. case cost)		
		Base Case - San Diego & LA	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,736	15,615	15,684	15,694	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(123)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,744)	(4,710)	(4,719)	(4,735)	(34)	(24)	(9)
4	Less IOU excess loss payments	(808)	(792)	(802)	(799)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,061	10,026	10,060	10,051	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	312	293	346	326	19	(34)	(14)
7	RMR Operating Payments - Levelized	60	48	60	58	12	-	2
8	CT Capacity Costs - Levelized	364	267	306	269	96	57	95
9	Transmission cost for new CTs-Levelized	128	94	108	95	34	20	33
10	Remediation cost to provide reactive support	-	-	-		-	-	-
11	System RA Provided by local capacity & RPS	(356)	(327)	(356)	(339)	(29)	-	(17)
12	**Subtotal Reliability Cost and Benefit**	508	376	464	409	**132**	**44**	**99**
13	**Total Energy and Reliability Benefits**					**168**	**44**	**109**
	RPS Procurement Cost							
14	Adjusted RPS Cost	5,312	5,256	5,312	5,270	56	-	41
15	**Total Benefits**					**224**	**44**	**150**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	8.5	97.0	(157)	(8.5)	(97.0)
17	**Total Costs and Benefits**	15,881	15,814	15,845	15,827	**67**	**36**	**53**

	Summary of Levelized Costs and Benefits	A	B	C	D	E	F	G
		Costs				Net Benefits		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,750	15,629	15,697	15,708	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(124)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,748)	(4,714)	(4,724)	(4,739)	(34)	(24)	(9)
4	Less IOU excess loss payments	(809)	(793)	(803)	(800)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,070	10,035	10,069	10,060	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	90	66	125	86	24	(35)	4
7	RMR Operating Payments - Levelized	60	48	60	58	12	-	2
8	CT Capacity Costs - Levelized	110	31	56	61	79	54	49
9	Transmission cost for new CTs-Levelized	39	11	20	21	28	19	17
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	26	-	(8)	(26)	-	8
12	**Subtotal Reliability Cost and Benefit**	299	182	261	218	**117**	**37**	**80**
13	**Total Energy and Reliability Benefits**					**152**	**38**	**90**
	RPS Procurement Cost							
14	Adjusted RPS Cost	5,320	5,264	5,320	5,264	**56**	**-**	**55**
15	**Total Benefits**					**209**	**38**	**146**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	9.3	205.2	**(157.0)**	**(9.3)**	**(205.2)**
17	**Total Costs and Benefits**	15,688	15,637	15,660	15,748	**52**	**29**	**(59)**

C. Lower reliability benefit for Sunrise

Q. What is the CAISO's opinion on the DRA's lower estimate of $66.4M for Sunrise's reliability benefit?

A. There are two main differences between the DRA and CAISO's estimates of reliability benefits for Sunrise. First, the DRA justifies its estimate based on its assessment that San Diego will have no capacity deficiency till 2015.[40] The CAISO concurs that SDG&E's advanced metering infrastructure (AMI) and on-going contracting efforts should be included in a reliability assessment and that they have the potential to defer the need for new capacity. As a result, the CAISO has reexamined the effect of AMI and power contracts on San Diego's capacity deficiency *sans* Sunrise. As discussed in Section 4 below, the reexamination confirms that year 2010 remains the first year of capacity deficiency.

The second major difference between the CAISO and DRA reliability analysis is that DRA assumes retirement of SDG&E's local generation at a continuous rate over a 10 year period until it has been entirely replaced. DRA has not produced any evidence that this is a more likely scenario than assuming South Bay retires and the other plants continue to operate or are mothballed until needed at a later date.

D. Reliability benefit of TE/VS

Q. What is the CAISO's opinion of TNHC's $126M/year estimate of the TE/VS project's reliability benefit in 2015?

A. THNC's estimate is based on the erroneous conclusion that (Green Path + LEAPS) provides the same reliability benefit as Sunrise. THNC asserts that the reliability benefit of TE/VS, and hence (Green Path + LEAPS), should be the

[40] Woodruff, Table ES-1.

same as Sunrise's benefit, that is derived from a 1000 MW increase in SDG&E's import limit. THNC reasons that the new facility and the Imperial Valley-Miguel 500 kV line would be the two contingencies setting the import limit in either case.[41] Because the 1000 MW is double the CAISO's estimate of 500 MW, THNC doubles the $63 million in reliability benefits that the CAISO found in its analysis of the (Green Path + LEAPS) alternative.[42]

TNHC claims that the TE/VS transmission alone would reduce the San Diego area LCR requirement by 1000 MW rather than the 500 MW determined by the CAISO in its detailed studies. In the description of the analysis performed to demonstrate the 1000 MW of LCR reduction, TNHC states "[t]o conduct this analysis, I am using the study methodology used by CAISO in its 2009-11 2011 Local Capacity Technical Analysis study, dated October 31, 2006, which included an import assessment for SDG&E."[43] Mr. Depenbrock goes on to state that the N-1-1 condition would be more severe than the G-1/N-1 condition. The CAISO is puzzled by this testimony because the reference document they claim to have followed explicitly provides the following analysis which describes how the G-1/N-1 condition is worse than the N-1-1 condition:

> In 2011 the most limiting contingency in the San Diego area is described by the outage of the 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations with the Otay Mesa Combined-Cycle Power plant (561 MW) out of service while staying within the maximum import achieved after the new Imperial Valley-San Felipe-Central 500 kV is in service (3,500 MW).

---

[41] Depenbrock, 9.
[42] Auclair, 31
[43] Depenbrock, 8.

* * *

> The outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations followed by San Felipe-Central 500 kV line will push the flow on South of San Onofre (WECC Path 44) to above its 2,500 MW rating; however all equipment will be within Applicable Rating. For consideration of LCR and in order to return the system to the import capability rating of Path 44 to 2,500 MW (within 30 minutes) the reliability criteria would permit load drop in San Diego if additional resource capacity in the area is not available.[44]

Presumably, TNHC missed this description of the LCR analysis of the San Diego area with the Sunrise project modeled, and this has caused them to come to incorrect conclusions about the relative LCR elimination benefits of the LEAPS transmission versus the Sunrise project.

Furthermore, THNC ignores the CAISO's analysis showing loading on the San Onofre – San Luis Rey 13 230kV # 1 line to be 99% of its emergency rating (1150 MVA) under the contingency of its parallel line at 500 MW of increased imports into San Diego Higher imports would require adding a fourth San Onofre – San Luis Rey 230kV line (18 miles). If the San Diego import capability were increased further, there would be a contingency overload of both the San Luis Rey-Mission #1 and #2 230 kV lines due to the loss of the Penasquitos-Old Town 230 kV line. The San Luis Rey-Mission #1 and #2 lines were at 91% of their emergency ratings.

THNC has provided no credible evidence that would convince the CAISO to alter its conclusion that the (Green Path + LEAPS) alternative would increase

[44] *Id.*, 75

import capability of the San Diego area by 500 MW. Hence, the CAISO sees no reason to double~~change~~ its ~~$63 million~~ estimate of the reliability benefits of (Green Path + LEAPS).

E. Fixed cost components of remote generation in the Sunrise case.

Q. Does the CAISO agree with THNC's statement that its Sunrise case "replaces the avoided in-basin generation with remote generation and renewable energy resources that are price only at LMP"[45] and does not include a fixed cost component?

A. No. The CAISO included the fixed cost component of the remote generation in the Sunrise case when estimating the RPS compliance costs included in the case. THNC misunderstands the CAISO's methodology, and its statement is without merit.

F. Mix of renewable resources throughout the West.

Q. Does the CAISO agree with THNC's claim that the CAISO testimony undercuts the preference for Imperial Valley resources by making the unrealistic assumption that all identified renewable resources throughout the West include the same mix of geothermal, wind and solar resources?[46]

A. No, THNC misunderstands the CAISO's methodology. The CAISO's analysis uses a different mix of renewable resources for the base case and Sunrise case. Each alternative can also have a different mix, depending on the transmission

---

[45] Auclair, 26
[46] *Id.*,19.

links that are constructed for the case, as explained in the CAISO's April 20, 2007 submission.[47]

3.3 RPS benefit estimation

Q. What are the parties' positions regarding the CAISO's estimation of RPS benefits?

A. The positions are as follows:

- Renewable energy deliverability. UCAN opines that renewable resources in Imperial Valley are deliverable to San Diego without Sunrise.[48] UCAN's reasoning is that "when the ISO was asked to model a situation with full development of Imperial Valley renewable energy – about 2700 new MW by 2015 – and no STP, its Gridview modeling showed that more than 99.94% of the 20,700+ GWh of Imperial Valley generation in 2015 in the with-STP case would also occur without STP."[49]
- Exclusion of non-CAISO customers and the "sunk" costs of Tehachapi transmission from RPS benefit computation. The DRA's base-case estimate is \$37M,[50] lower than the CAISO's estimate of \$56M.
- Range of RPS benefits**.** The DRA opines that a reasonable range of RPS benefits is \$0M/year to \$137M/year.[51]

[47] Second Errata to Initial Testimony of The California Independent System Operator Corporation, Part II, Application 06-08-010, April 20, 2007, Section 4.
[48] Marcus Confidential, 90.
[49] *Id.* , at 93
[50] Woodruff, Table ES-2.
[51] Woodruff, 36.

- <u>RPS benefit of TE/VS</u>. TNHC adopts the CAISO's 2015 estimate of -$28M for the TE/VS line.[52]

A. Renewable energy deliverability

Q. Does the CAISO agree with UCAN that 2700 MWs of renewable energy resources are likely to be developed in the Imperial Valley without Sunrise?[53]

A. No. The CAISO's reliability analysis of UCAN's alternatives to Sunrise shows that less than 700 MW of the 2700 MW potential could be reliably interconnected to the system and delivered to loads. The CAISO believes that UCAN has erroneously relied on the results of the Gridview runs conducted by the CAISO to support its conclusion that 2700 MW of new renewable load can be connected to the system and reliably delivered to load.

UCAN asked the CAISO to perform a reliability analysis on the 2015 Heavy Summer power flow model with 2700 MW of new renewable generation in Imperial County. UCAN also specified that a third Miguel 500/230 kV transformer should be modeled to alleviate the Miguel transformer loading limit, and that Path 42 should be upgraded. The CAISO modeled the case to UCAN's specifications, performed a powerflow, post-transient and stability analysis of that case and provided the results to UCAN. [54]. In those results the CAISO found that

[52] Auclair, 32.
[53] In its initial testimony, the CAISO assumed that 200MW of Imperial County renewables would be developed by IID. Therefore, the CAISO used 2500MW as the incremental amount of new renewables for the purposes of its analysis. However, because UCAN has used the full 2700 MW in its testimony, we will refer to that amount for this discussion.
[54] On March 30, 2007 the CAISO provided UCAN confidential transient stability results in the file named "transient_stability_results_v01.xls". These results identified a NERC/WECC System Adequacy and Security Criteria violation. Part III of the CAISO Testimony filed on April 20, 2007 described these results

mitigating the Miguel transformer loading limit and upgrading Path 42 was not an adequate plan of service to accommodate 2700 MW of generation in Imperial County, due to several reliability criteria violations produced by this model. Specifically, the most restrictive criteria violation was the transient frequency dip problem that the new generation would create in the Mexico CFE system. This problem would limit the installation of new generation in the Imperial County area without the Sunrise project, to 500 MW. Adding more generation in Imperial County only makes the impacts of this contingency worse.

Due to time constraints, the Gridview studies of this UCAN alternative were performed in parallel with the reliability studies and they did not consider these identified transmission constraints. Again as instructed by UCAN, the Gridview case included 2700 MW of Imperial County renewables generation. Thus, UCAN's testimony on renewable energy deliverability misinterprets the CAISO's two-prong approach to assess a transmission project's benefits by relying solely on the economic case while ignoring the transient stability results. The reliability analysis clearly shows that adding 2700 MW of generation in Imperial County without Sunrise would result in several reliability criteria violations.~~.~~~~[55]~~

Adding more than 700 MW of new generation in Imperial County *sans* Sunrise would degrade the transmission system's capability to withstand the

---

in the discussions of UCAN18 on Page 27, UCAN2 on Page 31, UCAN3 on Page 35, UCAN10 on Page 38, and UCAN12 on Page 42. On May 11, 2007, a confidential workpaper with a file name of "supplemental UCAN alternative analysis.doc" was provided to UCAN providing additional detail about the same reliability problem.

~~[55] Second Errata to Initial Testimony of The California Independent System Operator Corporation, Part II, Application 06-08-010, April 20, 2007, Table 5.1 at 80.~~

Imperial Valley-Miguel 500 kV outage, already the worst single contingency in the San Diego area and possibly the entire CAISO control area.

B. Exclusion of both non-CAISO customers and Tehachapi's "sunk" costs for the RPS procurement benefits.

Q. Do you agree with DRA's proposal to remove RPS procurement benefits related to non-TAC customers?

A. Yes. The DRA is correct that the RPS benefit estimation should exclude non-CAISO consumers. The DRA proposes to fix the CAISO error by removing the RPS benefits for non-TAC customers, resulting in (a) a reduction in levelized benefits of \$11M/year for the CAISO's case, or (b) \$9M/year for the DRA case where Tehachapi transmission costs are removed.

Q. Do you agree with the DRA's proposal to remove Tehachapi transmission costs from the renewable resource supply curve, which reduces Sunrise's RPS benefit?

A. No. While the CPUC has approved a portion of the estimated transmission cost for Tehachapi, including segments 1-3 at an estimated cost of approximately \$250 million, the vast majority of the project's total estimated costs of \$1.8 billion have not been approved yet and are therefore appropriately included in the cost of Tehachapi resources in this context. Despite the substantial amounts of incremental investments still required to fully develop Tehachapi, the DRA has removed the entire Tehachapi transmission cost from its RPS benefit estimation, making the 4500 MW of wind resources less expensive than the geothermal and solar resources in the Imperial Valley. The net impact of the DRA's cost removal on the CAISO's analysis is a $10M/year reduction in Sunrise's levelized RPS benefits.

The CAISO does not agree with DRA's adjustment. In fact, if the CAISO were to make any adjustment related to the Tehachapi project, it would be to increase our conservative estimates of the costs of the area's wind resources. With regard to the wind cost, the CAISO has assumed a wind resource cost of $66MWh.[56] Recently released figures from the CEC's June 2007 draft report on "Comparative Costs of Central Station Generation Technologies" indicate that the costs of wind have substantially increased to as high as $99/MWh.[57] While the CEC report is a draft staff report, the utilities attending the June 12, IPER workshop indicated that the bids they were receiving in their RFO's were near the market price referent levels, i.e., $85-90/MWh in 2010. [58]. Clearly the CAISO estimate is on the low side.

Q. Based on the evidence presented by DRA, does the CAISO propose to modify its levelized estimate of RPS procurement benefits for Sunrise?

A. Yes. The CAISO has modified its estimate of Sunrise's RPS benefit to eliminate benefits from non-TAC paying customers. This modification reduces the CAISO's estimate of RPS benefits from $56M/year to $45M/year, and reduces

[56] Second Errata to Initial Testimony of The California Independent System Operator Corporation, Part II, Application 06-08-010, April 20, 2007, 59.
[57] http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF
[58] The adopted market price referent is $86.52/MWh for a 20-year contract in CPUC Resolution E – 4049, December 14, 2006.

the estimate of Sunrise net benefits from the $67M~~52M~~/year estimate shown in Table 3 above, to $56M~~41M~~/year.

However, the CAISO rejects the DRA's removal of Tehachapi transmission because of the higher wind cost and unspent transmission dollars explained in the last answer. This lower estimate of RPS benefits, along with the proposed modifications already described, are shown in Table 4 below

Table 4: Levelized costs and benefits by alternative assuming Supplemental Non-Local Capacity Purchases, the $27/kW-year RA price floor and Exclusion of Non-TAC paying utilities.

		A	B	C	D	E	F	G
	Summary of Levelized Costs and Benefits	**Costs** ($ millions per year, nominal)				**Net Benefits** (Base case cost - Alt. case cost)		
		Base Case - San Diego & LA	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,736	15,615	15,684	15,694	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(123)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,744)	(4,710)	(4,719)	(4,735)	(34)	(24)	(9)
4	Less IOU excess loss payments	(808)	(792)	(802)	(799)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,061	10,026	10,060	10,051	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	312	293	346	326	19	(34)	(14)
7	RMR Operating Payments - Levelized	60	48	60	58	12	-	2
8	CT Capacity Costs - Levelized	364	267	306	269	96	57	95
9	Transmission cost for new CTs-Levelized	128	94	108	95	34	20	33
10	Remediation cost to provide reactive support	-	-	-		-	-	-
11	System RA Provided by local capacity & RPS	(356)	(327)	(356)	(339)	(29)	-	(17)
12	**Subtotal Reliability Cost and Benefit**	508	376	464	409	**132**	**44**	**99**
13	**Total Energy and Reliability Benefits**					**168**	**44**	**109**
	RPS Procurement Cost							
14	Adjusted RPS Cost	4,265	4,220	4,265	4,232	45	-	33
15	**Total Benefits**					**213**	**44**	**142**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	8.5	97.0	(157)	(8.5)	(97.0)
17	**Total Costs and Benefits**	14,834	14,779	14,799	14,789	**56**	**36**	**45**

		A	B	C	D	E	F	G
	Summary of Levelized Costs and Benefits	**Costs**				**Net Benefits**		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,750	15,629	15,697	15,708	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(124)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,748)	(4,714)	(4,724)	(4,739)	(34)	(24)	(9)
4	Less IOU excess loss payments	(809)	(793)	(803)	(800)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,070	10,035	10,069	10,060	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	90	66	125	86	24	(35)	4
7	RMR Operating Payments - Levelized	60	48	60	58	12	-	2
8	CT Capacity Costs - Levelized	110	31	56	61	79	54	49
9	Transmission cost for new CTs-Levelized	39	11	20	21	28	19	17
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	26	-	(8)	(26)	-	8
12	**Subtotal Reliability Cost and Benefit**	299	182	261	218	**117**	**37**	**80**
13	**Total Energy and Reliability Benefits**					**152**	**38**	**90**
	RPS Procurement Cost							
14	Adjusted RPS Cost	4,272	4,227	4,272	4,227	**45**	**-**	**45**
15	**Total Benefits**					**198**	**38**	**135**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	9.3	205.2	**(157.0)**	**(9.3)**	**(205.2)**
17	**Total Costs and Benefits**	14,640	14,600	14,612	14,711	**41**	**29**	**(70)**

C San Diego Capacity Need Date

Q. The DRA's assessment of San Diego's local capacity requirement (LCR) need *sans* Sunrise indicates no capacity deficiency until 2015.[59] Does the CAISO agree with this assessment?

A. No, the CAISO does not concur that 2015 is the first year of capacity deficiency. The DRA's LCR revises SDG&E's assessment by including the capacity (MW) provided by SDG&E's Advanced Metering Infrastructure (AMI) and contracts with J Power (Pala), Wellhead Power Maragarita and EnerNOC. The CAISO concurs that AMI, demand response and planned new generation should be part of the determination of LCR, and we have updated our calculations accordingly. However, San Diego loads are growing more rapidly than anticipated, as evidenced by the latest CEC staff forecast (May 2007, CEC-200-2007-006). Because the new CEC forecast has higher SDG&E demand and growth than the prior forecast, the revised capacity deficiency date remains at 2010, as shown in Table 5 below.

[59] Woodruff, Table ES-1.

Table 5: San Diego Locational Capacity Requirement[60]

[60] The San Diego area 1 in 10-year extreme weather load forecast data in line 1 comes from the May 2007 CEC Staff Forecast of 2008 Peak Demand. The San Diego area load growth between 2006 and 2008 is 1.7% per year. This growth rate was assumed constant through the year 2020.
Adjustments were made to this load forecast in lines 2 through 6 to represent the California Solar Initiative and three different demand response programs. The CAISO position on counting demand response programs for local reliability purposes is still evolving. However, for the purposes of this proceeding, the CAISO will count the revised SDG&E load reduction attributed to AMI for determining the resource need year. The revised SDG&E estimates are based on SDG&E's response to Energy Division data request number 4 which was also provided to the CAISO in response to our data request. These estimates were then adjusted to reflect the impact of losses.

Line 8 = generation capacity expected to be in operation in 2008. Lines 9 through 15 = new resources expected to come into operation over the next few years, based on SDG&E resource procurement information. Line 16 = the expected retirement of South Bay Power Plant in 2010.

Local capacity requirements in the San Diego area are established so that during the outage of the largest generating unit followed by worst single transmission line outage all load in the San Diego area (i.e. line 7 of the attachment) can be reliably served. Currently the largest generator in the area is the 541.5 MW Palomar unit. In 2010 the 561 MW Otay Mesa unit will be the largest unit in the area as shown on line 18. The worst single transmission line outage is the Imperial Valley-Miguel 500 kV line outage, and in order to avoid load shedding, the import power flow into San Diego must be maintained at or below 2500 MW. Also, during this transmission line outage condition power losses increase by approximately 58 MW as shown on line 19, and this incremental increase in losses must be met by internal resources in order to maintain import flows below 2500 MW. This value of 58 MW is the difference between the 155 MW of losses in the Reference Case during the G-1/N-1 condition in Table 5.1 of the CAISO testimony and the 97 MW of losses in the same case for only the G-1 condition. Line 20 = local load (line 7 + line 19) less (line 17 – line 18. Line 22 = the surplus capacity available to meet the San Diego local load (Line 20 – Line 21).

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Reference
	Load Forecast														
1	1 in 10 CEC Forecast	4999	5084	5170	5258	5348	5439	5531	5625	5721	5818	5917	6017	6120	CEC-200-2007-006
2	-CA Solar Initiative	2	6	10	25	60	100	130	150	150	150	150	150	150	SDGE testimony 1/26/07
3	-Celerity(Demand Response)	20	20	20	20	20	20	20	20	20	20	20	20	20	SDGE testimony 1/26/07
4	-Comverge(Demand Response)	9	9	9	9	9	9	9	9	9	9	9	9	9	SDGE testimony 1/26/07
5	-EnerNOC(Demand Response)	30	30	30	30	30	30	30	30	30	30	30	30	30	
6	-AMI(Demand Response)	0	47.07	88.9	194	203	213	218	223	229	234	240	246	252	SDGE data response
7	Net 1 in 10 Load Forecast	4938	4972	5012	4980	5025	5067	5124	5193	5283	5375	5468	5563	5659	
	Generation														
8	2008 Posted NQC	2917	2917	2917	2917	2917	2917	2917	2917	2917	2917	2917	2917	2917	Net Qualifying Capacity Values and LCR for Compliance Year 2008 - Corrections as of 30-May-2007
9	+SDCWA - Rancho Penasquitos	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	SDGE testimony 8/4/06
10	+Bull Moose (Biomass)		20	20	20	20	20	20	20	20	20	20	20	20	SDGE testimony 8/4/06
11	+Otay Mesa Combined Cycle		561	561	561	561	561	561	561	561	561	561	561	561	CEC website
12	+Lake Hodges Pump Storage Hydro	40	40	40	40	40	40	40	40	40	40	40	40	40	ISO Queue
13	+J Power (Pala)	94	94	94	94	94	94	94	94	94	94	94	94	94	2008 SDGE contract info
14	+Wellhead Power Margarita	44	44	44	44	44	44	44	44	44	44	44	44	44	2008 SDGE contract info
15	+Palomar inlet air chiller			20	20	20	20	20	20	20	20	20	20	20	
16	-South Bay Retirement			-702	-702	-702	-702	-702	-702	-702	-702	-702	-702	-702	
17	Total Generation	3100	3681	2999	2999	2999	2999	2999	2999	2999	2999	2999	2999	2999	
	Locational Capacity Requirement														
18	Largest G-1	541.5	561	561	561	561	561	561	561	561	561	561	561	561	
19	Loss Adjustment (Note 2)	58	58	58	58	58	58	58	58	58	58	58	58	58	Table 5.1 ISO testimony 4/20/07 (Reference case vs N-1)
20	Import Capacity Need (Load-Gen)	2438	1910	2633	2600	2646	2687	2744	2813	2903	2995	3088	3183	3279	
21	Import Capacity Limit	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	
22	Surplus (Deficiency)	62	590	(133)	(100)	(146)	(187)	(244)	(313)	(403)	(495)	(588)	(683)	(779)	

Note 1: Sunrise Powerlink or alternative transmission projects are not considered in this table
Note 2: Loss adjustment needed to reflect N-1/G-1 condition

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Reference
	Load Forecast														
1	1 in 10 CEC Forecast	4999	5084	5170	5258	5348	5439	5531	5625	5721	5818	5917	6017	6120	CEC-200-2007-006
2	-CA Solar Initiative	2	6	10	25	60	100	130	150	150	150	150	150	150	SDGE testimony 1/26/07
3	-Celerity(Demand Response)	20	20	20	20	20	20	20	20	20	20	20	20	20	SDGE testimony 1/26/07
4	-Comverge(Demand Response)	9	9	9	9	9	9	9	9	9	9	9	9	9	SDGE testimony 1/26/07
5	-EnerNOC(Demand Response)	30	30	30	30	30	30	30	30	30	30	30	30	30	
6	-AMI(Demand Response)	0	43.3	81.8	179	187	196	201	206	211	216	221	226	232	SDGE data response
7	Net 1 in 10 Load Forecast	4938	4976	5020	4996	5041	5084	5141	5210	5301	5393	5487	5582	5679	
	Generation														
8	2008 Posted NQC	2917	2917	2917	2917	2917	2917	2917	2917	2917	2917	2917	2917	2917	Net Qualifying Capacity Values and LCR for Compliance Year 2008 - Corrections as of 30-May-2007
9	+SDCWA - Rancho Penasquitos	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	SDGE testimony 8/4/06
10	+Bull Moose (Biomass)		20	20	20	20	20	20	20	20	20	20	20	20	SDGE testimony 8/4/06
11	+Otay Mesa Combined Cycle		561	561	561	561	561	561	561	561	561	561	561	561	CEC website
12	+Lake Hodges Pump Storage Hydro	40	40	40	40	40	40	40	40	40	40	40	40	40	ISO Queue
13	+J Power (Pala)	94	94	94	94	94	94	94	94	94	94	94	94	94	2008 SDGE contract info
14	+Wellhead Power Margarita	44	44	44	44	44	44	44	44	44	44	44	44	44	2008 SDGE contract info
15	+Palomar inlet air chiller			20	20	20	20	20	20	20	20	20	20	20	
16	-South Bay Retirement			-702	-702	-702	-702	-702	-702	-702	-702	-702	-702	-702	
17	Total Generation	3100	3681	2999	2999	2999	2999	2999	2999	2999	2999	2999	2999	2999	
	Locational Capacity Requirement														
18	Largest G-1	541.5	561	561	561	561	561	561	561	561	561	561	561	561	
19	Loss Adjustment (Note 2)	58	58	58	58	58	58	58	58	58	58	58	58	58	Table 5.1 ISO testimony 4/20/07 (Reference case vs N-1)
20	Import Capacity Need (Load-Gen)	2438	1914	2640	2616	2662	2704	2762	2831	2921	3014	3107	3203	3300	
21	Import Capacity Limit	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	
22	Surplus (Deficiency)	62	586	(140)	(116)	(162)	(204)	(262)	(331)	(421)	(514)	(607)	(703)	(800)	

Note 1: Sunrise Powerlink or alternative transmission projects are not considered in this table
Note 2: Loss adjustment needed to reflect N-1/G-1 condition

Q. How does this estimation of LCR differ from what the CAISO used in its 04/20/07 testimony?

A. The reference case results in Table 5.1 of the CAISO's 4/20/07 testimony showed the need for 565 MW of local resources in 2015 to meet the San Diego local capacity requirements. The new table reduces the need to 313MW~~331MW~~ in 2015 (Line 22). The table also shows that the first year of deficiency occurs in 2010.

Q. What major drivers underlie the change in need requirements?

A. The major drivers are listed below. We have also indicated how much each driver changes the local capacity deficiency in 2015. The net effect is a 252MW reduction in 2015 compared to the results shown on Table 5.1 of the CAISO's April 20, 2007, testimony.

- The San Diego area 1-in-10-year extreme weather load forecast data in line 1 comes from the May 2007 CEC Staff Forecast of 2008 Peak Demand. The San Diego area load growth between 2006 and 2008 is 1.7% per year, and is higher than the prior 2006 CEC forecast. This growth rate was assumed constant through the year 2020. This change amounted to an increase in load of +186MW between 2010 and 2020.
- Additional demand response reduction was included for the EnerNOC program (-30MW)
- AMI has been included as a reduction to peak demand. The CAISO position on counting demand response programs for local reliability purposes is still evolving. However, for the purposes of this proceeding, the CAISO will count the load reduction attributed to AMI by SDG&E for determining the resource need year. SDG&E provided its translation of the assumptions in

D.07-04-043 into peak load reductions beginning in 2010 through 2020 in response to a data request, and the CAISO will accept interpretation of the Commission's decision for the purposes of this analysis.[61]The CAISO has adjusted the values upward for 5.86 percent distribution losses and 2.68% transmission losses. (-223MW)

- Net Qualifying Capacity Values and LCR for Compliance Year 2008 was corrected as of 30-May-2007. (-2.5MW)
- SDCWA and Bull Moose generation were added (-24.5MW)
- J. Power and Wellhead Power generators were added (-138MW)
- Palomar air inlet chiller was added (-20MW)

Q. What is the impact of the new LCR estimates on the economics of the alternatives?

A. The lower LCR requirements reduce the amount of RMR contract capacity and CT capacity required in both the base and alternative cases. The lower LCR also reduces the RMR capacity price ($/kW-yr) in those years when the RMR capacity requirement is lower than the total available in-area RMR[62]. The lower LCR requirements reduce the levelized net benefits of the Sunrise project another $4M~~3M~~ from $56M~~41M~~/year to $52M~~38M~~/year.

---

[61] See SDG&E's 6/14/07 response to the CAISO's Second data request.

[62] The CAISO has revised the relationship between RMR surplus levels and RMR capacity prices. The prior analysis varied prices when RMR capacity under contract was between (a) 680MW, which was the CAISO's estimated by amount of RMR required with Sunrise in service in 2010; and (b) 1440MW, which was the total amount of RMR estimated to be available in the area without postponement of South Bay retirement. If the RMR need was below 680MW, the price was set at the floor of $27/kW-yr (in $2006 dollars); and if it was above San Diego's existing RMR generation of 1440MW, the price was set at the ceiling of $50/kW-yr (in 2010 dollars). While the new relationship uses the same price floor and ceiling, it uses a 900MW range of 540MW to 1440MW so that the 540MW starting point reflects the lower LCR requirements.

Table 6: Levelized costs and benefits by alternative assuming Supplemental Non-Local Capacity Purchases, the $27/kW-year RA price floor, Exclusion of Non-TAC paying utilities, and Revised Local Capacity Requirements

		A	B	C	D	E	F	G
	Summary of Levelized Costs and Benefits	**Costs** ($ millions per year, nominal)				**Net Benefits** (Base case cost - Alt. case cost)		
		Base Case - San Diego & LA	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,736	15,615	15,684	15,694	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(123)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,744)	(4,710)	(4,719)	(4,735)	(34)	(24)	(9)
4	Less IOU excess loss payments	(808)	(792)	(802)	(799)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,061	10,026	10,060	10,051	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	312	287	341	320	25	(29)	(8)
7	RMR Operating Payments - Levelized	60	43	60	55	17	(0)	5
8	CT Capacity Costs - Levelized	363	278	315	276	85	49	87
9	Transmission cost for new CTs-Levelized	128	98	111	97	30	17	31
10	Remediation cost to provide reactive support	-	-	-		-	-	-
11	System RA Provided by local capacity & RPS	(356)	(327)	(356)	(339)	(29)	-	(17)
12	**Subtotal Reliability Cost and Benefit**	507	379	471	409	**129**	**37**	**98**
13	**Total Energy and Reliability Benefits**					**164**	**37**	**109**
	RPS Procurement Cost							
14	Adjusted RPS Cost	4,265	4,220	4,265	4,232	45	**-**	33
15	**Total Benefits**					**209**	**37**	**142**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	8.5	97.0	(157)	(8.5)	(97.0)
17	**Total Costs and Benefits**	14,834	14,782	14,805	14,789	**52**	**29**	**45**

		A	B	C	D	E	F	G
	Summary of Levelized Costs and Benefits	**Costs**				**Net Benefits**		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,750	15,629	15,697	15,708	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(124)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,748)	(4,714)	(4,724)	(4,739)	(34)	(24)	(9)
4	Less IOU excess loss payments	(809)	(793)	(803)	(800)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,070	10,035	10,069	10,060	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	90	58	120	79	32	(30)	11
7	RMR Operating Payments - Levelized	60	42	60	55	18	-	5
8	CT Capacity Costs - Levelized	93	26	48	52	67	45	41
9	Transmission cost for new CTs-Levelized	33	9	17	18	24	16	15
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	26	-	(8)	(26)	-	8
12	**Subtotal Reliability Cost and Benefit**	276	162	245	196	**114**	**31**	**81**
13	**Total Energy and Reliability Benefits**					**150**	**32**	**91**
	RPS Procurement Cost							
14	Adjusted RPS Cost	4,272	4,227	4,272	4,227	**45**	**-**	**45**
15	**Total Benefits**					**195**	**32**	**136**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	9.3	205.2	**(157.0)**	**(9.3)**	**(205.2)**
17	**Total Costs and Benefits**	14,618	14,580	14,596	14,688	**38**	**22**	**(70)**

Q. How would the net benefits change for (Green Path + LEAPS) if the advanced pumped storage were treated as a transmission asset?

A. Treating pumped storage as a transmission asset would require three changes to the analysis: (1) the levelized cost of the pumped storage ($128M/yr) would be added to the Transmission cost, (2) the levelized AS and energy benefits of the pumped storage unit ($95M/yr) would be subtracted from the transmission cost resulting in a net Transmission cost of $33M/yr, and (3) the pumped storage would provide RMR and RA capacity to the system at zero cost. Making these changes only slightly reduces the levelized net benefit for (Green Path + LEAPS) from $45M/yr in Table 6 to $44M/yr in Table 6B.

Table 6B: Levelized costs and benefits by alternative assuming Supplemental Non-Local Capacity Purchases, the $27/kW-year RA price floor, Exclusion of Non-TAC paying utilities, Revised Local Capacity Requirements, LEAPS as a Transmission Asset

		A	B	C	D	E	F	G
	Summary of Levelized Costs and Benefits	**Costs** ($ millions per year, nominal)				**Net Benefits** (Base case cost - Alt. case cost)		
		Base Case - San Diego & LA	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,736	15,615	15,684	15,694	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(123)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,744)	(4,710)	(4,719)	(4,735)	(34)	(24)	(9)
4	Less IOU excess loss payments	(808)	(792)	(802)	(799)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,061	10,026	10,060	10,051	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	312	287	341	288	25	(29)	24
7	RMR Operating Payments - Levelized	60	43	60	55	17	(0)	5
8	CT Capacity Costs - Levelized	363	278	315	276	85	49	87
9	Transmission cost for new CTs-Levelized	128	98	111	97	30	17	31
10	Remediation cost to provide reactive support	-	-	-		-	-	-
11	System RA Provided by local capacity & RPS	(356)	(327)	(356)	(339)	(29)	-	(17)
12	**Subtotal Reliability Cost and Benefit**	507	379	471	377	**129**	**37**	**130**
13	**Total Energy and Reliability Benefits**					**164**	**37**	**141**
	RPS Procurement Cost							
14	Adjusted RPS Cost	4,265	4,220	4,265	4,232	45	**-**	33
15	**Total Benefits**					**209**	**37**	**174**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	8.5	129.8	(157)	(8.5)	(129.8)
17	**Total Costs and Benefits**	14,834	14,782	14,805	14,790	**52**	**29**	**44**

D. Range of RPS benefits.

Q. What is the CAISO's opinion on the DRA's range of RPS benefit estimates for Sunrise?

A. The CAISO finds the DRA's range unreasonable. Although zero benefits is possible, it is extremely unlikely and therefore should *not* be the low end of a plausible range. The CAISO believes that its Sunrise RPS benefit estimate is conservative and should be adopted as the low end of a plausible range.

The CAISO's opinion is based on the following information and conclusions:

- SDG&E has indicated in public workshops that it has signed contracts with Stirling at a price significantly below the 12 cents per KWh estimate used by the CAISO. (March 27, 2007 Workshop). Also, other studies have projected costs in the 8-10 cents per kWh range.[63] Reducing the solar thermal cost to 10 cents per kWh would increase the annual RPS procurement benefit to CAISO participants by approximately $32M/year.[64]
- As noted above, the updated cost estimate and actual bids for wind resources are substantially higher than the $66/MWh assumed in the CAISO's analysis.[65] The CEC recently estimates Class 5 Wind costs at $99/MWh.[66] Being conservative, the CAISO has used, a wind cost of $85/MWh in 2010[67] for wind generation in California and Reno Nevada for estimating the high end of RPS benefit range. The $85/MWh wind

[63] See, for example, "Presentation to the CEC on Solar Thermal Electricity Costs, 2003 Integrated Electricity Report" that references an independent report prepared by Sargent and Lundy under the auspices of DOE indicating levelized costs of Solar Thermal in the 8 to 10 cent range in the 2007 time frame.
[64] The lower solar thermal cost estimate also reduces any economic benefits from Sunrise project deferral. Section 4 details the Sunrise deferral cases.
[65] Second Errata to Initial Testimony of The California Independent System Operator Corporation, Part II, Application 06-08-010, April 20, 2007, 62.
[66] CEC Draft Report :Comparative Costs of Central Station Electricity Generation Technologies, June 2007, Table 2.
[67] This is less than the adopted market price referent of $86.52/MWh for a 20-year contract in CPUC Resolution E – 4049, December 14, 2006.

cost would increase the Sunrise RPS benefits to CAISO participants by another $35M/year.

- The recent rejection of the Palo Verde-Devers II project by the Arizona Public Service Commission highlights the difficulty of developing new transmission projects for the purpose of importing power from another jurisdiction into California. The CAISO's base case recognizes this difficulty and assumes that only 50% of the renewable projects requiring long transmission lines connecting to other jurisdictions would ultimately materialize.[68] In light of Arizona's recent decision, our base case assumption may be optimistic. To be sure, states like Wyoming and Montana may welcome new resource development for power export. However, California's closest neighbors all have growing loads and their own renewables portfolio standards. A more realistic assumption may be that only 25% of the projects requiring extensive transmission projects could be implemented. This modification would increase the RPS benefits to CAISO participants by an additional $108M/year.

These three changes in assumptions lead the CAISO to estimate that the high end of a plausible range of RPS benefit estimates to CAISO participants would be $220M/year, which is the sum of (a) the CAISO's original $45M/year levelized benefit for Sunrise (after adjusting for non-TAC customers);[69] (b) $32M/year for lower solar thermal costs; (c) $35M/year for wind costs at $85/MWh level, and

[68] Second Errata to Initial Testimony of The California Independent System Operator Corporation, Part II, Application 06-08-010, April 20, 2007, at 67.
[69] Second Errata to Initial Testimony of The California Independent System Operator Corporation, Part II, Application 06-08-010, April 20, 2007, at 45.

(d) $108M/year due to less renewable energy supply from other jurisdictions that oppose new transmission designed exclusively for exports into California.

Table 7: Levelized costs and benefits by alternative assuming Supplemental Non-Local Capacity Purchases, the $27/kW-year RA price floor, Exclusion of Non-TAC paying utilities, Revised Local Capacity Requirements, and High End RPS Benefits

	Summary of Levelized Costs and Benefits	A	B	C	D	E	F	G
		Costs ($ millions per year, nominal)				Net Benefits (Base case cost - Alt. case cost)		
		Base Case - San Diego & LA	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,736	15,615	15,684	15,694	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(123)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,744)	(4,710)	(4,719)	(4,735)	(34)	(24)	(9)
4	Less IOU excess loss payments	(808)	(792)	(802)	(799)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,061	10,026	10,060	10,051	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	312	287	341	320	25	(29)	(8)
7	RMR Operating Payments - Levelized	60	43	60	55	17	(0)	5
8	CT Capacity Costs - Levelized	363	278	315	276	85	49	87
9	Transmission cost for new CTs-Levelized	128	98	111	97	30	17	31
10	Remediation cost to provide reactive support	-	-	-		-	-	-
11	System RA Provided by local capacity & RPS	(356)	(327)	(356)	(339)	(29)	-	(17)
12	**Subtotal Reliability Cost and Benefit**	507	379	471	409	**129**	**37**	**98**
13	**Total Energy and Reliability Benefits**					**164**	**37**	**109**
	RPS Procurement Cost							
14	Adjusted RPS Cost	4,718	4,498	4,718	4,555	220	-	163
15	**Total Benefits**					**383**	**37**	**271**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	8.5	97.0	(157)	(8.5)	(97.0)
17	**Total Costs and Benefits**	15,286	15,060	15,257	15,112	**226**	**29**	**174**

	Summary of Levelized Costs and Benefits	A	B	C	D	E	F	G
		Costs				Net Benefits		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,750	15,629	15,697	15,708	121	53	42
2	Less CAISO congestion cost (reduces TAC)	(124)	(88)	(102)	(110)	(36)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,748)	(4,714)	(4,724)	(4,739)	(34)	(24)	(9)
4	Less IOU excess loss payments	(809)	(793)	(803)	(800)	(16)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	10,070	10,035	10,069	10,060	**35**	**1**	**10**
6	RMR Capacity Payments - Levelized	90	58	120	79	32	(30)	11
7	RMR Operating Payments - Levelized	60	42	60	55	18	-	5
8	CT Capacity Costs - Levelized	93	26	48	52	67	45	41
9	Transmission cost for new CTs-Levelized	33	9	17	18	24	16	15
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	26	-	(8)	(26)	-	8
12	**Subtotal Reliability Cost and Benefit**	276	162	245	196	**114**	**31**	**81**
13	**Total Energy and Reliability Benefits**					**150**	**32**	**91**
	RPS Procurement Cost							
14	Adjusted RPS Cost	4,725	4,505	4,725	4,505	**220**	**-**	**220**
15	**Total Benefits**					**369**	**32**	**311**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	9.3	205.2	**(157.0)**	**(9.3)**	**(205.2)**
17	**Total Costs and Benefits**	15,071	14,859	15,049	14,965	**212**	**22**	**106**

Q. Why do the different RPS procurement assumptions cause the large changes in Sunrise RPS benefits?

A. The price changes are the easiest to explain. The Sunrise case has more solar thermal resources, and the base case has more wind resources. Therefore any decrease in solar costs will lower the cost of the procuring renewable in Sunrise. Similarly, any increase in the wind cost will increase the cost of procuring renewable resources in the base case. The effect of changing our assumption that 50% of the long distance out-of-state resources could be purchased by CA utilities to 25% is best explained with the aid of two RPS supply curves. Figure 1 below shows the RPS supply curve under the assumption that 50% of out-of-state renewables could be purchased by California utilities. The ellipse in the middle of the chart shows the cost and supply of Imperial Valley renewables that would be built if Sunrise is constructed. It shows that the Sunrise induced mix of resources costs slightly more than 105 $/MWh. If Sunrise is not constructed, the output from those Imperial Valley renewables would need to be replaced by the resources identified by the second ellipse. One can see that the replacement renewables are only slightly higher cost than the Imperial Valley renewables. This is the reason why the CAISO estimates that the construction of Sunrise will result in a positive but moderate amount of RPS cost savings, under the conservative assumptions used in our Initial Testimony.

REBUTTAL TESTIMONY OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
A.06-08-010

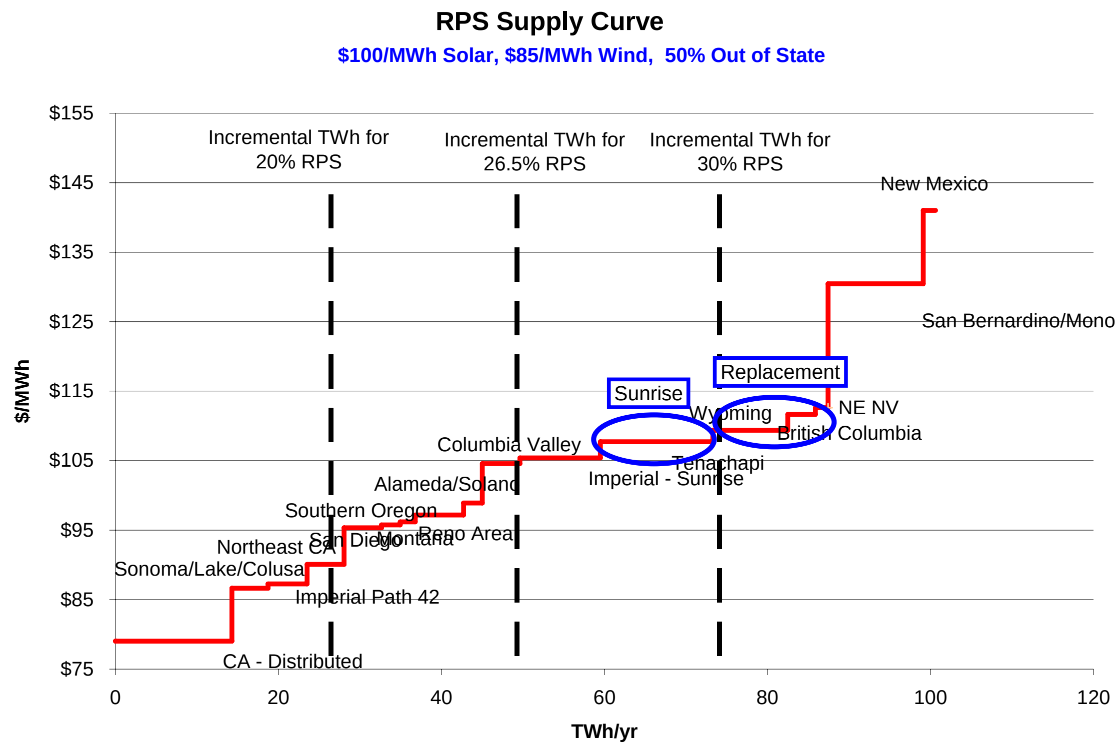


Figure 1: RPS Supply Curve - 50% of Out-of-State Resources

Figure 2 shows the RPS supply curve if only 25%, rather than 50%, of long distance out-of-state renewable resources can be imported to California. The ellipses again indicate the Sunrise Imperial Valley renewables, and the replacement renewables that would be needed if Sunrise were not built (looking at years 2020 and beyond). In this case, the replacement renewables are far more costly (127 $/MWh) than the Imperial Valley renewables (105 $/MWh), hence the large RPS savings from building Sunrise in the 25% out-of-state scenario.

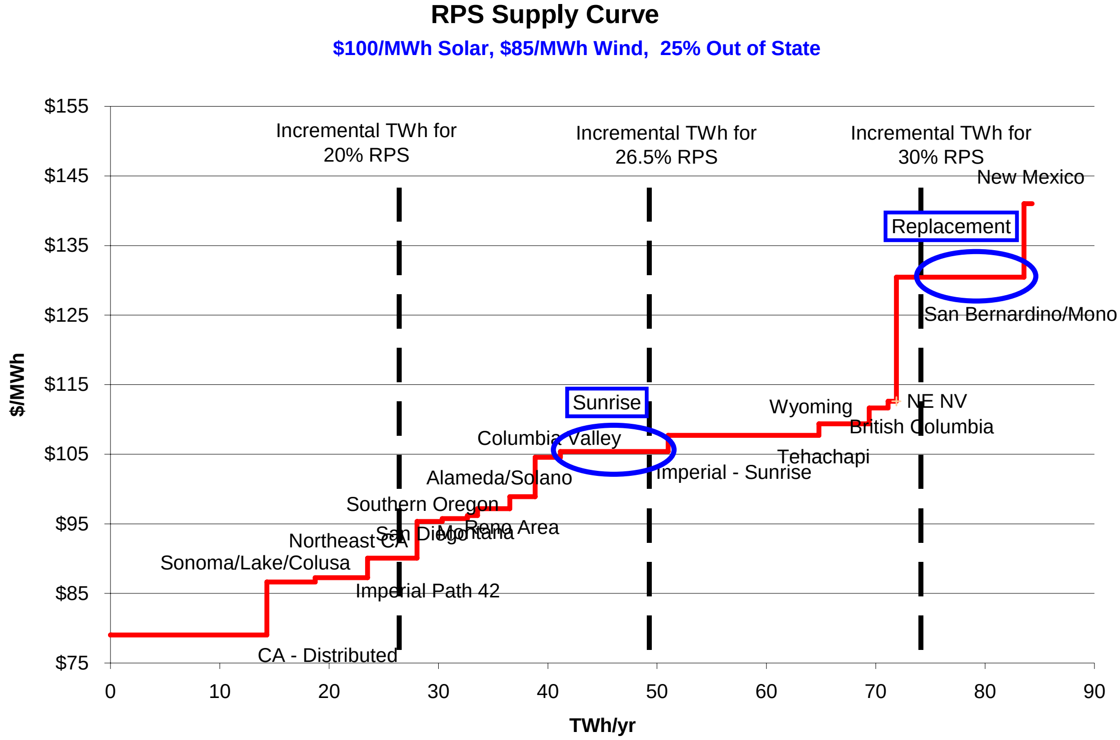


Figure 2: RPS Supply Curve - 25% of Out-of-State Resources

Q. Will building Green Path North before Sunrise reduce Sunrise's RPS benefits to zero?

A. No, it will not for the following reasons:

- <u>The CAISO's recently developed reliability analysis indicates that only 2000 MW of renewables could be reliably connected and delivered with Green Path, as compared to 2700MW with Sunrise.</u>~~Even though our economic evaluation for Green Path North makes the generous assumption that all of the Imperial Valley renewable resource potential could be delivered to loads over this new transmission line, the CAISO's recently developed reliability~~

~~analysis indicates that only 500 MW is deliverable.~~~~[70]~~ Sunrise would still be required to facilitate the development of the remaining resources.

- The CAISO's assumed 900 MW of solar thermal resources developed in the Imperial Valley is probably too low. If both Green Path North and Sunrise were built, it would be very likely that the area would be built to its full solar thermal potential of approximately 2,000 MW. The 2000-MW estimate is consistent with studies completed by CRS and NREL;[71] and we have confirmed these estimates in telephone conversations with Stirling.

E. RPS benefit of TE/VS

Q. Does the CAISO concur with THNC that the RPS compliance benefits of the TE/VS transmission line in the absence of Green Path North would be negative $28M [in 2015], identical to the benefits under the (Green Path + LEAPS) alternative?[72]

A. No. The CAISO has not studied the TE/VS alternative's RPS compliance costs. However, the TE/VS line alone would not allow the development of the Imperial Valley renewable resources that are the source of the RPS benefits for Sunrise and

~~[70] Second Errata to Initial Testimony of The California Independent System Operator Corporation, Part II, Application 06-08-010, April 20, 2007, Table 5.1 at 80.~~

[71] The estimate of 2000 MW of solar thermal generation potential in the Salton Sea/IID area is derived from the estimate of 10,000 MW of solar thermal potential in California in the "CRS Report" 33% report completed for the CEC in 2005 and referenced on page 55 of the CAISO April 20th 2007 Testimony.

This 2000 MW estimate is confirmed by NREL, which estimated a potential of about 10,000 MW for the area of California with a solar resource greater than 7.5 kWh/m2-day, and which passed the screen of terrain with a slope of 1% or less. Of this amount, about 20% of the state's resource is in the Salton Sea/IID area based on NREL solar mapping, and most of the rest is in the Mojave Desert.

The 2000 MW figure conservative estimate because it refers to locations with only the very highest quality resource. An acceptable solar generation resource of 6.75 kWh/m2-day would imply that Imperial Valley alone has a solar potential of about 30 GW.

[72] Auclair, 32.

the (Green Path + LEAPS) alternative. It is more reasonable to assume that the RPS resources developed under TE/VS would be identical to those developed in the Base Case. Therefore, the RPS benefits of a standalone TE/VS line would be zero.

4. The CAISO's opinions on alternatives recommended by the interveners.

Q. How did the CAISO proceed with studying the intervener's alternative scenarios and presenting these scenarios in its direct testimony?

A. Although the active parties in this case are very familiar with the process that has been followed by the CAISO for studying intervener alternative scenarios since the issuance of the November 1, 2006 Assigned Commissioner/ALJ Scoping Ruling, a short summary will be helpful here.

On December 7, 2006, the interveners submitted requests for the CAISO to study numerous alternative scenarios. When it became apparent that the CAISO could not possibly complete all of the necessary model runs and file testimony on January 26, 2007, in accordance with the procedural schedule for the case, the CAISO requested an extension of time to complete these studies. Based on informal conversations with the Commission staff prior to filing its motion for extension on January 8, 2007, the CAISO agreed to complete its analysis of four cases for the January 26, 2007 testimony: 1) a base case with certain specified assumption changes; 2) the base case with Sunrise; 3) the base case with LEAPS + GreenPath North; and 4) the base case with South Bay repowered. The CAISO agreed to proceed with its analysis of the other proposed alternative scenarios in accordance with a schedule set forth in the motion. In an ALJ/ACR ruling on January 26, the CAISO-proposed procedural schedule was modified, and with certain minor changes, that schedule has been followed to date.

Q. What has the CAISO done in analyzing the other alternatives not addressed in Parts I and II of its initial testimony?

A. The CAISO provided the "raw" results of the model runs to the interveners in two large batches at the end of February and March, 2007, and in numerous other transmittals during the course of its ongoing study process. In its April 20, 2007 testimony,[73] the CAISO "packaged" numerous computer runs and provided subsequent analysis to estimate the benefits of alternatives specified by the parties and to assess the reliability performance of the alternatives. Additional runs were also conducted for Rancho Penasquitos Concerned Citizens (RPCC) and UCAN following the submission of the April 20, 2007 testimony, and these results were packaged and submitted on May 14, 2007. Finally, on June 22, 2007, the CAISO will submit packaged results for model runs requested by the Commission's Energy Division and by the Aspen environmental consultants.

It is important to note that with the exception of the four alternatives studied in Parts I and II of its initial testimony, the CAISO has not offered an opinion as to the feasibility or viability of the alternative scenarios. Now that the inteverners have filed testimony advancing certain scenarios as alternatives to Sunrise, the CAISO will take a position on these proposals.

[73] The CAISO Initial Testimony, Part III, April 20, 2007.

Q. Please describe the alternatives analyzed by the CAISO at the request of third parties and now proposed to the Commission as alternatives to Sunrise.

A. These alternatives are:

(1) Miguel limitation relief. UCAN states that the Commission should order SDG&E to upgrade the Miguel substation to increase the import capability to 1900 MW and outflow capability to 2100 MW.[74]

(2) Mexico Light. UCAN opines that the Commission should order SDG&E to study the feasibility of implementing Mexico Light, whether or not Sunrise is going to be built.[75] The DRA does not consider Mexico Light as a feasible alternative to Sunrise to meet San Diego's reliability needs.[76]

(3) Path 44 upgrade. UCAN recommends the upgrade be pursued, whether Sunrise is going to be built or not.[77] In its Path 44 upgrade discussion, UCAN also indicates that the CAISO's current reliability criteria are too conservative by not taking probability into account.[78]

(4) Sunrise deferral. UCAN opines that Sunrise should be deferred because it is not cost-effective until 2018;[79] this is notwithstanding that UCAN also recommends SDG&E to obtain rights-of-way now to avoid cost escalation due to urban development in the western portion of Sunrise's route.[80] The DRA's

---

[74] Marcus, Confidential, 12.
[75] *Id.* 50.
[76] Zanininger, K. Report on The Sunrise Powerlink, Phase 1 Direct Testimony, Volume 2 of 5, DRA, CPUC, May 18, 2007, at 11 (Zanininger).
[77] Marcus Confidential, 13.
[78] Marcus Confidential, 21, footnote 58.
[79] Shames, UCAN Testimony on Overview of Technical Testimony, SDG&E Misinformation and Alternatives, at 5 (Shames).
[80] Marcus Confidential, 215.

assessment of San Diego's local capacity requirement (LCR) need *sans* Sunrise indicates no capacity deficiency until 2015.[81]

(5) Second Southwest Power Link (SWPL II). UCAN recommends that SWPL II should be reconsidered.[82] The DRA also considers SWPL II as a feasible alternative to Sunrise to meet San Diego's reliability needs.[83]

(6) Talega-Escondido/Valley-Serrano (TE/VS). TNHC believes that TE/VS should not be bundled into the (Green Path + LEAPS) analysis,[84] and that TE/VS provides nearly equal benefits as Sunrise at one-third of Sunrise's cost.[85]

4.1 Miguel limitation relief

Q. Does the CAISO agree with UCAN that the import and outflow capabilities on the Miguel line should be increased?

A. The CAISO agrees that if Sunrise were not built and new renewable generation were to be added to Imperial County, the current Miguel transformer constraint would need to be alleviated. In fact, the CAISO assumed in its reference case, which included 600 MW of new renewable generation in Imperial County, that a third Miguel transformer would be installed to alleviate the constraint.

UCAN has proposed a cheaper alternative for alleviating this constraint, which the CAISO agrees should be considered when it is needed. However, currently

[81] Woodruff, Table ES-1.
[82] Marcus Confidential, e 48.
[83] Zaninger, 6.
[84] Depenbrock, 13
[85] Auclair, 33.

the Miguel transformer limit is not causing any significant uneconomic generation dispatch.

If Sunrise were built, it would mitigate the Miguel transformer flows so neither a third Miguel transformer nor the UCAN's proposed Miguel transformer tripping scheme would be needed.

Q. Does the CAISO agree with UCANs position that 2700 MW of new renewable generation in the Imperial County can be reliably interconnected and delivered by relieving the Miguel Transformer limit and upgrading Path 42 (IID-SCE)?

A. No. As explained above in Section 3.3 A., UCAN has erroneously concluded that because the CAISO and San Diego were able to model 2500 MW of new renewable generation in Imperial County without the Sunrise Powerlink project in the Gridview model, this new generation can be reliably delivered to load. However, the reliability studies performed by the CAISO for the same scenario showed that mitigating the Miguel transformer loading limit and upgrading Path 42 was not an adequate plan of service to accommodate 2700 MW of generation in Imperial Valley.

4.2 Mexico Light

Q. What is the CAISO's opinion on Mexico Light?

A. UCAN states that "The Mexico Light alternative is a very low-cost way to add 165 Mw of capacity, for reliability purposes, to SDG&E's system."[86] The

[86] Marcus Confidential, 50.

CAISO's does not believe that this option could be easily implemented in the immediate future for the following reasons:

- The statement assumes that detailed operating procedures could be developed to allow the Mexico Light alternative to create generation capacity available to San Diego load during the critical contingency. This may not occur without (a) the necessary capacity contracts to be signed by SDG&E or the CAISO with the generation owner; and (b) and operating agreements and transmission service agreements with CFE.
- The statement assumes that the CFE would continue to be connected to the CAISO system during the critical Imperial Valley-Miguel transmission contingency. Based on its recent actions to modify their special protection systems for this summer season, however, the CFE may end up connected to the IID system, rather than the CAISO system, after the outage of the Imperial Valley- Miguel line. This change of settings to the special protection system in the future would render the UCAN alternative infeasible.

4.3 Path 44 Upgrade

Q. What is the CAISO's opinion on Path 44 Upgrade?

A. UCAN states "The Path 44 upgrade option consists of taking a fresh look at the Path 44 study to see what has changed since the original study, and what might be changed in the future, in order to allow the Path 44 limit to be increased above 2500 Mw under N-1 conditions."[87]

[87] Marcus Confidential, 14.

The CAISO found bulk system reliability criteria violations when we analyzed this alternative. Although UCAN offers mitigation costs for these identified problems, the CAISO remains concerned that increasing the Path 44 rating would degrade the security of the CAISO transmission system compared to the system with the Sunrise project. This is because the upgrade without Sunrise can cause a transient frequency dip on the Mexico CFE system as well as thermal overloads.[88]

The CAISO believes that the stability performance issues found earlier are primarily caused by increasing generation in Imperial County without adding the Sunrise project. Increasing reliance on Path 44 would also tend to exacerbate this same stability performance issue.

Even if one were willing to accept the reduction in system performance, the cost savings for this alternative are questionable because increasing reliance on Path 44 to reduce the San Diego LCR requirements will cause an almost equal increase the SCE LCR requirements. To see this point, assume that the Path 44 upgrade would reduce the San Diego area LCR requirement by 350 MW. This LCR reduction would cause 350 MW of additional generation in the San Diego area to be temporarily mothballed, until load growth was sufficient to drive up LCR contract prices to cover the plants' fixed and variable operating costs.[89]

[88] The CAISO Initial Testimony, Part III, April 20, 2007, 28.
[89] We have assumed that the mothballed plants would not be available to sign contracts to meet the LCR needs of the LA Basin. If the mothballed generators in the SDG&E area were available to provide capacity support to the LA Basin, then they could be used to meet the increased LCR requirement in the LA Basin.

However, a brief analysis and a review of the existing studies[90] showed that this reduction of generation in San Diego would increase the LCR requirements in the LA Basin by approximately 350 MW. The brief analysis also showed that the San Diego area generation has approximately the same effectiveness as the LA Basin generation on reducing flow on the South of Lugo constraint which dictates the LCR requirements in the LA Basin

4.4 Sunrise deferral

Q. UCAN states that "deferring STP saves ratepayers $33 million levelized dollars per year in 2010-2049, using the ISO's numbers and methodology."[91] Does the CAISO concur with UCAN's statement?

A. The CAISO concurs that deferring STP can result in incremental benefits relative to the original timing under certain assumptions. However, the CAISO's estimate of the benefits of deferral is considerably smaller than UCAN's, and is highly sensitive to the assumed construction cost escalation rate. Under what the CAISO believes is the most plausible escalation rate, UCAN's suggestion of deferring STP until 2018 results in negative incremental benefits.

In order to respond to UCAN's deferral recommendation, the CAISO performed a timing analysis to evaluate the economics of deferring the Sunrise project. The economics of deferral depend critically on both the cost escalation

[90] CAISO 2008 Local Capacity Technical Analysis can be found at http://www.caiso.com/1bb5/1bb5ed3d46430.pdf Pages 69-71 show effectiveness factors of generation on the South of Lugo constraint. SONGS could be used as a proxy for San Diego generation and has an effectiveness factor that is approximately the median value in the list of factors.
[91] Marcus Confidential, 77.

rate for the transmission project and the assumptions used to forecast the cost of different renewable resource types.

While the CAISO does not agree with UCAN's assumed 3.1% annual escalation rate, its analysis determines that using the UCAN 3.1% escalation rate, incorporating many of UCAN's assumptions, and deferring Sunrise to 2018 would increase the levelized net benefits of Sunrise by $15.7M per year. The "optimal" in-service date that maximizes Sunrise's net benefits under UCAN's assumptions would be 2016. At a more plausible transmission cost escalation rate of 5.5 percent, the 2018 in-service date *reduces* the levelized annual net benefit by $6M per year. The "optimal" in-service date under the CAISO's assumptions would be 2013.

Q. How did the CAISO construct its deferral analysis that yields the $15M per year estimate of UCAN's 2018 deferral case?

A. The CAISO constructed a deferral analysis based on its April 20th filing. The CAISO then included several changes to address the following issues raised by UCAN and DRA:

- The SDG&E loads and resources that determine LCR have been updated to include load reductions for SDG&E's AMI, DR and new CT generation. (See Table 5 above)
- The floor for RMR contract payments has been changed from $10.72/kW-year to $27/kW-year.
- The discount rate has been changed from 8.18%/year to 8.23%/year to incorporate the Commission findings in SDG&E's AMI Decision.

- The annual growth in capacity requirements has been changed to match those in Table 5 above.
- The CAISO has modeled a system RA benefit of $27/kW-yr (2006 dollars) that is assigned to all RMR, new in-area CTs, and capacity provided by renewable resources purchased in both the base and Sunrise cases. The main effect of this change is to reduce the benefits of the Sunrise case because that case purchases fewer local RMR capacity (MW), and therefore is credited with less system RA benefit. This reduction in RA from local RMR is somewhat offset by the increased RA-qualifying capacity available from the Sunrise renewable resource mix compared to the base case renewable resource mix. The Sunrise mix provides more RA-qualifying capacity because it replaces some of the base case wind resources with solar thermal resources. The CAISO has counted 70% of the installed capacity of solar thermal for RA, as compared to 20% for wind.
- RPS benefits are reduced by 19.7% to reflect RPS purchases by non-TAC paying entities.

Other updates to the analysis include:

- The base 1-in-10-year SDG&E load forecast is based on the CEC's latest May 2007 demand forecast.
- Reliability costs for the LA Basin are included, and the analysis includes the RMR capacity provided by renewable generation to the LA Basin.
- The present value and levelization period was previously fixed to cover the 40 year period of 2010 - 2049. To develop a full investigation of deferral

benefits, the study period now is 40 years after the Sunrise in-service date, which may vary from 2010 to 2020.

Q. How do Sunrise's benefits vary with the planned on line date?

A. The pattern of benefits over the range of different in-service dates is as follows:

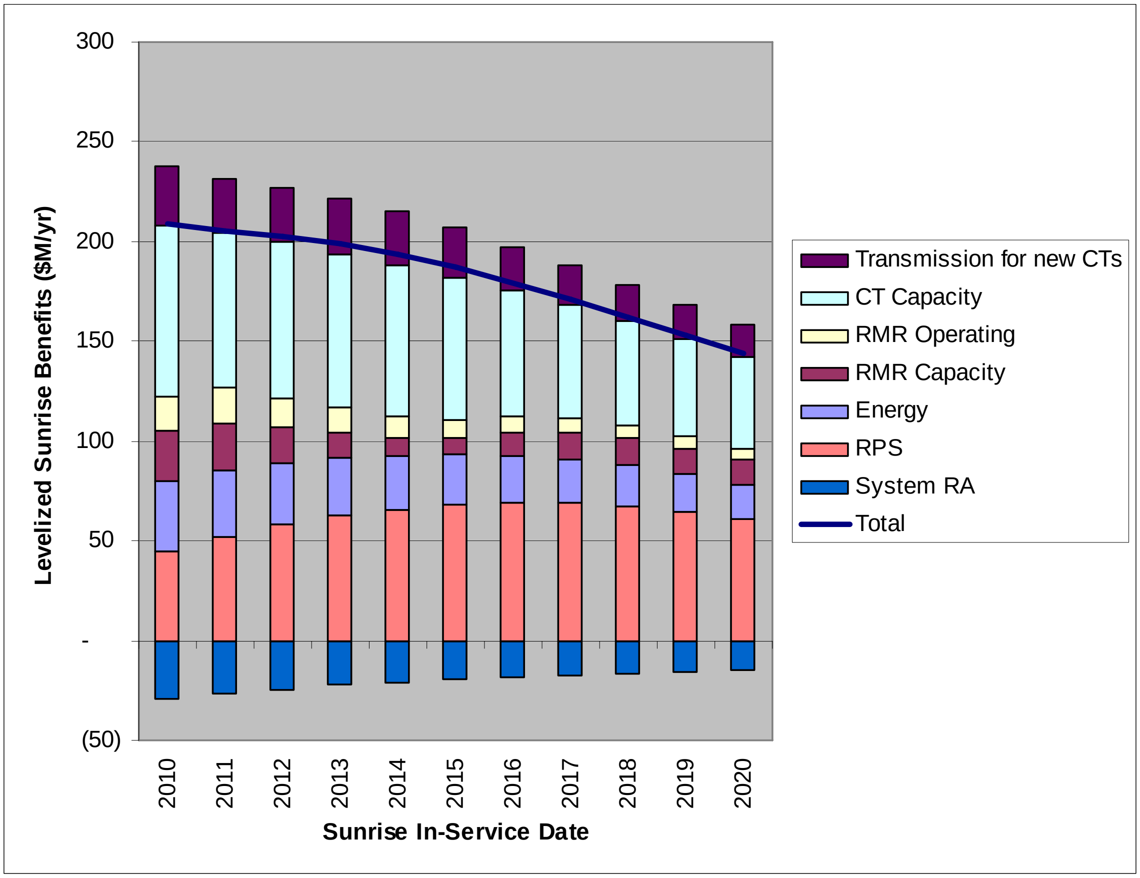
- RPS benefits. These benefits increase with the Sunrise project deferral. This occurs primarily because the Sunrise case includes 900 MW of solar thermal resources that have a relatively high delivered cost when compared to renewable resources in the base case. Thus, deferring Sunrise up to five years helps consumers achieve procurement cost savings. As the years progress, the base case resource plan has the CAISO consumers procuring increasing amounts of renewable energy from increasingly costly sources. Eventually, the base case's renewable resource mix is more costly than the Sunrise-enabled resource mix; and the RPS benefits begin to decline if Sunrise is delayed past 2016.[92]
- Energy benefits. These benefits decline with the Sunrise deferral. The Sunrise project is estimated to provide energy-related benefits each year that it is in service. Delaying Sunrise eliminates those benefits in the years 2010 until the delayed in-service date.

[92] Although the CAISO continues to believe that its RPS procurement benefits provide a conservative base case, the deferral benefits are in large part driven by the assumed differences in costs between wind resources purchased at $66 /MWh and solar thermal thermal costs purchased at $120 per MWh. As described earlier in our testimony, an alternative plausible case brings the costs of these two resources closer and essentially eliminates any deferral benefit.

- RMR (local capacity) benefits. These also decline because delaying Sunrise increases the RMR costs. Without Sunrise, more RMR MWs are purchased at a higher RMR price.
- RMR operating benefits. These benefits decline because the RMR operation cost increases with the amount of RMR MWs purchased. Without Sunrise, higher RMR purchases equate to higher operating costs in the deferral period.
- CT benefits. These decline because more CT capacity is purchased in the years prior to the Sunrise in-service date. This additional CT capacity directly increases the CT costs in the deferral period. The CAISO also expects that the new CT capacity would be signed under long-term contracts and obligates SDG&E to continue paying any new CTs even after Sunrise is built.
- CT-related transmission benefits. These benefits decline for the same reason that the costs of CTs themselves decline.
- System RA benefits. System RA is a cost (or negative benefit) in the Sunrise case because the additional RA that must be purchased to replace the RA reduction made possible by Sunrise. This cost declines with the deferral of Sunrise because the deferral delays the need for SDG&E to procure RA to replace the RA reduction.

Q. What is the overall benefit impact of deferring Sunrise's in-service date?

A. The total benefits of Sunrise implemented in 2010 are approximately $209M~~195M~~/year. If the project is delayed 10 years to 2020, its benefits decline to $144~~142~~ million/year.

1 
300
250
200
150
100
50
-
(50)
Levelized Sunrise Benefits ($M/yr)
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Sunrise In-Service Date
Transmission for new CTs
CT Capacity
RMR Operating
RMR Capacity
Energy
RPS
System RA
Total

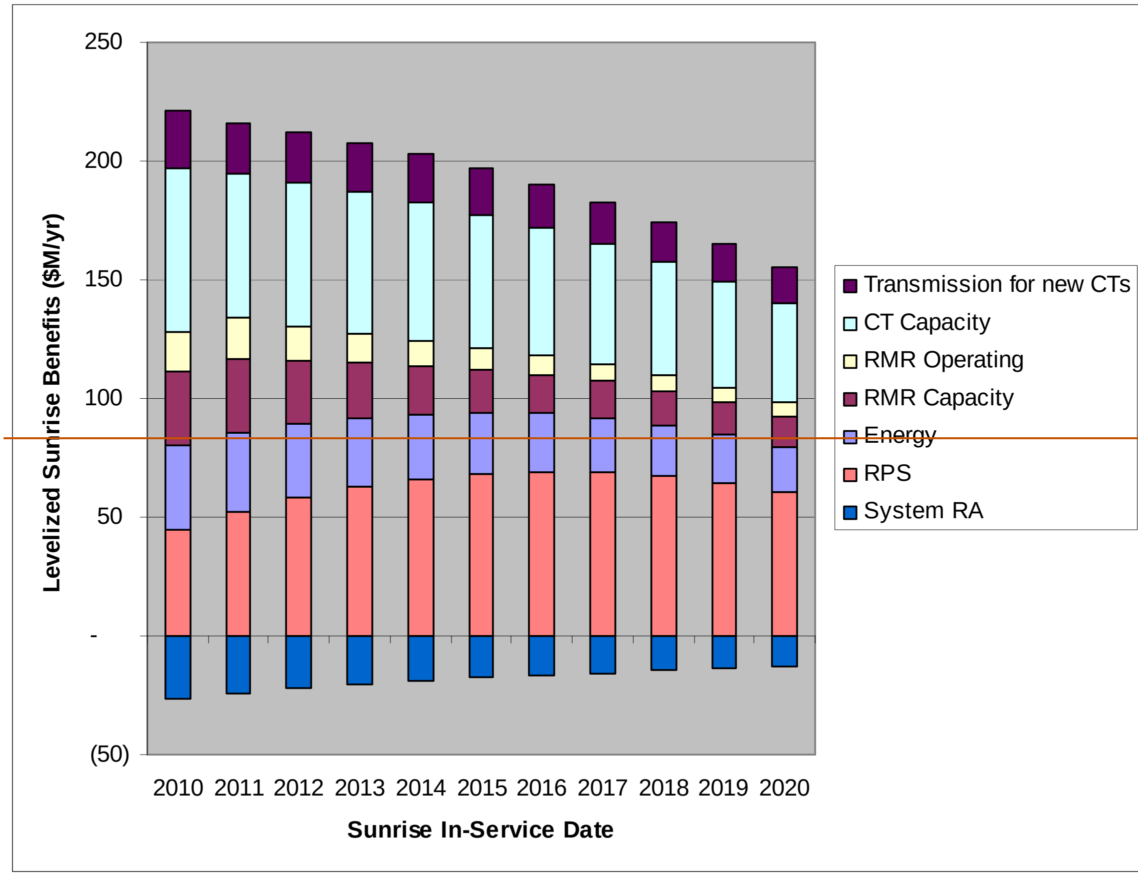


Figure 3: Levelized Benefits Incorporating 4/20/07 Estimate of RPS Benefits (does not include the change in construction costs from deferring transmission)

Q. What is the <u>net benefit</u> impact of deferring Sunrise's in-service date to 2018, as recommended by UCAN?

A. To derive the net benefit impact, the CAISO first estimates the cost savings to ratepayers from deferring capital investment. This estimation entails taking the $157M levelized value in 2010 dollars, escalated it by UCAN's 3.1% per year, and discounted it by UCAN's 8.23% discount rate. The net result for UCAN's suggested 2018 in-service date~~data~~ is an increase of $3.8M~~15.7M~~ in the net benefits of Sunrise.

Q. **Can the Commission rely upon a single $3.8M~~15.7M~~/year deferral value to decide the optimal timing of the Sunrise project?**

A. No, because: (a) if the future project cost escalation rates are higher than UCAN's 3.1% estimate, as the CAISO believes, the benefits of deferring Sunrise decline; and (b) the benefits of deferral are highly sensitive to changes in RPS costs.

Q. **What is the basis for the CAISO's belief that transmission escalation will exceed UCAN's 3.1% estimate?**

A. Recent years have seen rapid increases in construction costs due to factors such as global demand for raw materials in China and India. The DRA acknowledges this rapid escalation in its testimony.[93] The Edison Electric Institute shows transmission cost escalation rates that average 9.0% per year (9.5%, 8.0%, and 9.4%) for the 2004 -2006 period.[94] VELCO's Northwest Vermont Reliability Project, Docket 6860, shows a 10% per year escalation rate.[95] SDG&E responded to the CAISO data request that labor costs have increased 30% in two years, and component cost increases are approximately 80% per year.[96]

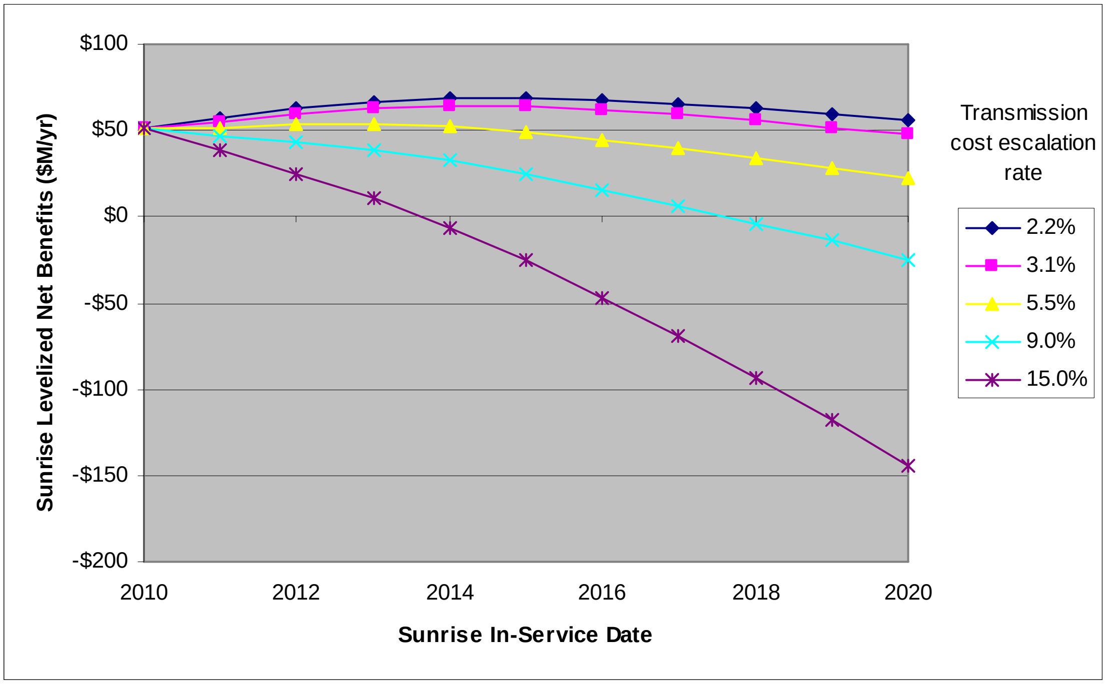
Q. **How would Sunrise net benefits change under different transmission cost escalation assumptions?**

---

[93] Woodruff, 45.
[94] Table 9.1 Construction Expenditures for Transmission and Distribution, available at http://www.eei.org/industry_issues/energy_infrastructure/transmission/Transmission-Investment-expenditures.pdf. The cost escalation rate is computed as the difference between (a) the nominal expenditure growth rate; and (b) the real expenditure growth rate.
[95] The original estimate was filed on June 5, 2005 based on estimates prepared in 2002 and 2003. The adopted estimates were 29% higher and presented to VELCO in June 2005. Assuming 2.5 years of inflation, the annual inflation rate is 10%.
[96] SDG&E response number 3 to CAISO data request No. 1.

A. The figure below shows Sunrise net benefits by in-service date and cost escalation. Based on Table 5, each line on the figure shows the relationship between Sunrise benefits and in-service dates, conditional on a specific transmission cost escalation rate. From this figure, the following observations can be made:

- At the 3.1% escalation rate, the in-service date with the highest net benefits is 2014~~2016~~.
- At the 5.5% escalation rate, the in-service date with the highest net benefits is 2013.
- At the 9% escalation rate, the 2010 in-service date produces the highest net benefits.
- If the escalation rate turns out to be 15%, Sunrise's benefits declines rapidly with deferral, turning negative in year 2014~~2013~~ due to increased construction costs.



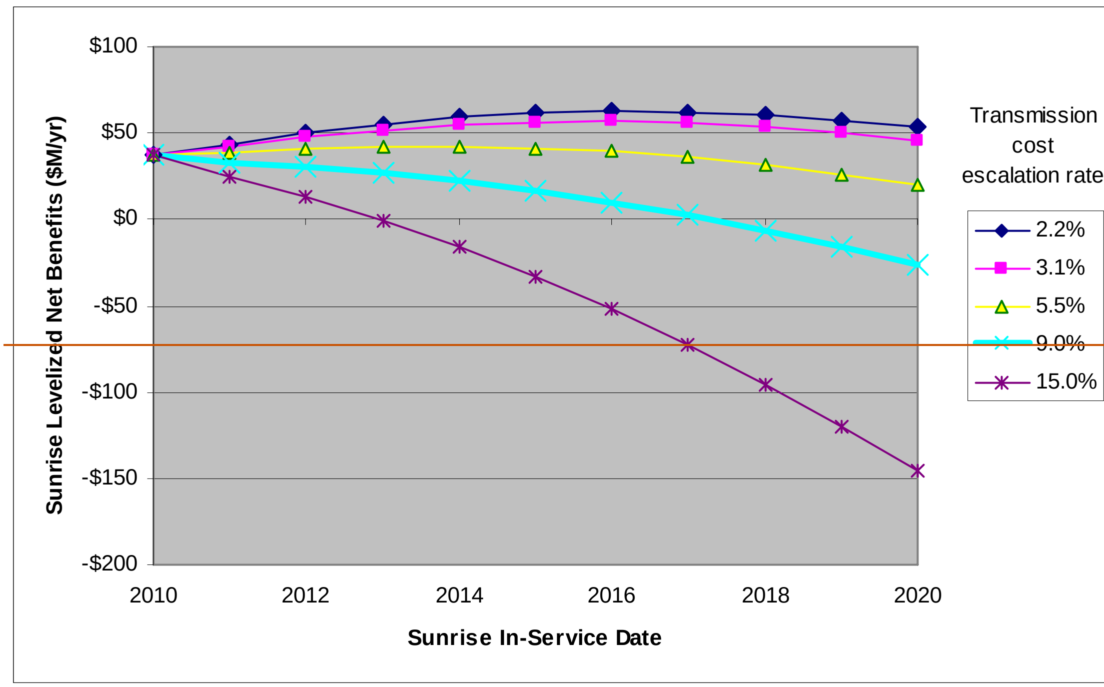


Figure 4: Sunrise Levelized Net Benefits

Table 8A~~5~~: Sunrise Levelized Net Benefits ($million/yr)

	Transmission cost escalation rate				
	2.2%	3.1%	5.5%	9.0%	15.0%
2010	$ 51.9	$ 51.9	$ 51.9	$ 51.9	$ 51.9
2011	$ 56.6	$ 55.3	$ 51.8	$ 46.7	$ 38.0
2012	$ 62.5	$ 60.0	$ 53.3	$ 43.2	$ 25.2
2013	$ 66.6	$ 63.1	$ 53.4	$ 38.4	$ 10.4
2014	$ 69.0	$ 64.6	$ 52.1	$ 32.4	$ (6.3)
2015	$ 69.3	$ 64.0	$ 49.0	$ 24.5	$ (25.5)
2016	$ 67.9	$ 61.9	$ 44.5	$ 15.3	$ (46.8)
2017	$ 65.6	$ 58.9	$ 39.4	$ 5.7	$ (69.4)
2018	$ 62.9	$ 55.7	$ 34.1	$ (4.0)	$ (93.0)
2019	$ 59.6	$ 51.9	$ 28.6	$ (14.0)	$ (117.7)
2020	$ 55.4	$ 47.3	$ 22.3	$ (24.6)	$ (144.1)

	Transmission cost escalation rate				
	2.2%	3.1%	5.5%	9.0%	15.0%
2010	$ 37.4	$ 37.4	$ 37.4	$ 37.4	$ 37.4
2011	$ 43.1	$ 41.8	$ 38.3	$ 33.2	$ 24.5
2012	$ 50.1	$ 47.6	$ 40.9	$ 30.9	$ 12.9
2013	$ 55.3	$ 51.8	$ 42.1	$ 27.2	$ (0.8)
~~2014~~	~~$ 58.9~~	~~$ 54.5~~	~~$ 42.0~~	~~$ 22.2~~	~~$ (16.4)~~
2015	$ 61.3	$ 56.0	$ 41.0	$ 16.5	$ (33.5)
2016	$ 62.6	$ 56.6	$ 39.2	$ 10.1	$ (52.0)
2017	$ 62.1	$ 55.5	$ 35.9	$ 2.3	$ (72.8)
2018	$ 60.3	$ 53.1	$ 31.6	$ (6.6)	$ (95.5)
2019	$ 57.4	$ 49.7	$ 26.4	$ (16.2)	$ (119.9)
2020	$ 53.5	$ 45.4	$ 20.4	$ (26.5)	$ (146.0)

Q. What other significant uncertainties can affect the deferral value of Sunrise?

A. As shown in Figure 3 above, the RPS cost of renewable resources is the major reason for the positive deferral value that accrues under relatively low rates of transmission cost inflation.

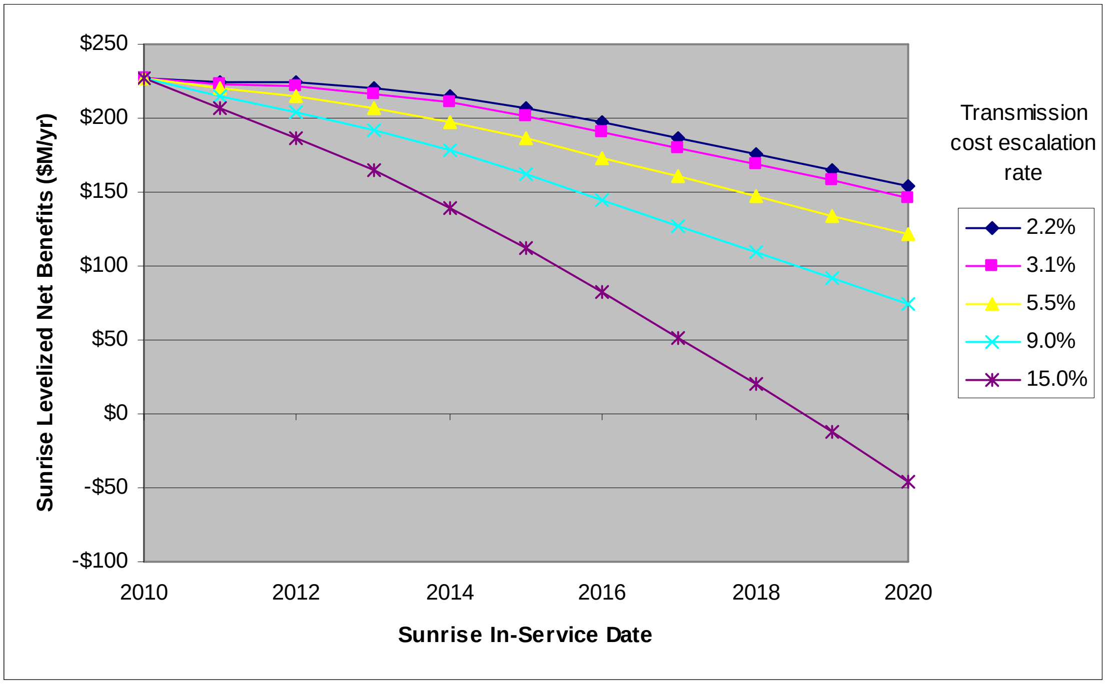
The CAISO recognizes that the cost of delivered renewable resources is uncertain, as is the assumption regarding the amount of renewable resources that California could import from regions outside of California. As an alternate scenario, the CAISO has modeled solar thermal at $100/MWh, wind at $85/MWh, and has assumed that California could import only 25% of the renewable energy available from long distance out-of-state sources (as compared to the 50% assumption in the CAISO's April 20, 2007 analysis).

This alternative RPS procurement Scenario is consistent with the following assumptions:

- The solar thermal industry can benefit from market transformation and technological improvements;[97]
- The higher wind prices are much closer to the market price referent for 2010, consistent with utility reports of recent bids received; and
- California utilities will have a very difficult time procuring out-of-state renewable resources due to the many difficult siting issues associated with "long-line" multi-jurisdictional transmission projects, as evidenced by the Arizona Corporation Commission's recent rejection of the Palo Verde-Devers project.

Figure 5 (based on Table 8) shows that the benefits of delaying Sunrise disappear under this alternate RPS cost scenario. At each escalation rate above 2.2% shown in the figure, the 2010 in-service date has the highest benefit. Moreover, this small change in renewable technology cost assumptions increases the annual net benefits of the Sunrise project to $226~~over $200~~ million per year.

[97] House, L. Report on The Sunrise Powerlink, Phase 1 Direct Testimony, Volume 5 of 5, DRA, CPUC, May 18, 2007.



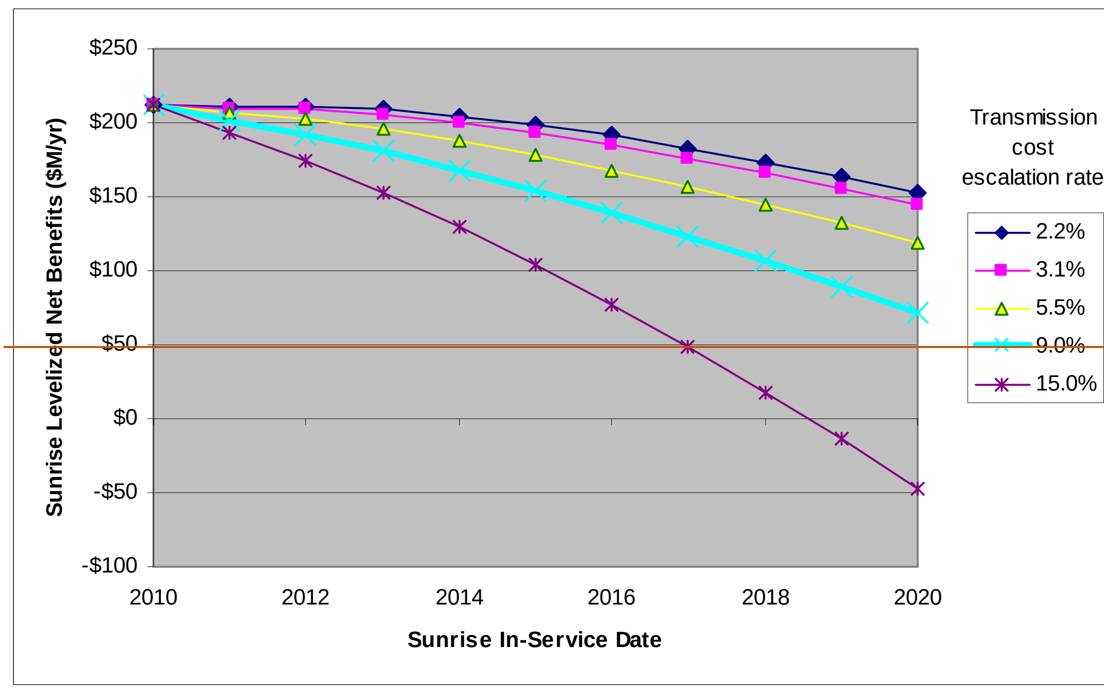


Figure 5: Sunrise Project Levelized Net Benefits - Alternate RPS Scenario

Table 8<u>B</u>: Sunrise Project Levelized Net Benefits - Alternate RPS Scenario

	Transmission cost escalation rate				
	2.2%	3.1%	5.5%	9.0%	15.0%
2010	$ 226.4	$ 226.4	$ 226.4	$ 226.4	$ 226.4
2011	$ 224.9	$ 223.6	$ 220.1	$ 215.0	$ 206.3
2012	$ 223.8	$ 221.3	$ 214.6	$ 204.6	$ 186.5
2013	$ 220.4	$ 216.8	$ 207.1	$ 192.2	$ 164.2
2014	$ 214.8	$ 210.4	$ 197.9	$ 178.2	$ 139.5
2015	$ 206.8	$ 201.5	$ 186.5	$ 162.0	$ 112.0
2016	$ 196.8	$ 190.8	$ 173.5	$ 144.3	$ 82.2
2017	$ 186.5	$ 179.8	$ 160.3	$ 126.6	$ 51.5
2018	$ 176.0	$ 168.8	$ 147.3	$ 109.1	$ 20.2
2019	$ 165.4	$ 157.7	$ 134.3	$ 91.8	$ (12.0)
2020	$ 154.2	$ 146.1	$ 121.1	$ 74.2	$ (45.3)

	Transmission cost escalation rate				
	2.2%	3.1%	5.5%	9.0%	15.0%
2010	$ 212.0	$ 212.0	$ 212.0	$ 212.0	$ 212.0
2011	$ 211.4	$ 210.1	$ 206.6	$ 201.5	$ 192.8
2012	$ 211.4	$ 209.0	$ 202.3	$ 192.2	$ 174.2
2013	$ 209.1	$ 205.6	$ 195.9	$ 180.9	$ 153.0
~~2014~~	~~$ 204.7~~	~~$ 200.3~~	~~$ 187.8~~	~~$ 168.0~~	~~$ 129.4~~
2015	$ 198.8	$ 193.5	$ 178.5	$ 154.0	$ 104.0
2016	$ 191.6	$ 185.6	$ 168.2	$ 139.1	$ 76.9
2017	$ 183.0	$ 176.3	$ 156.8	$ 123.1	$ 48.0
2018	$ 173.5	$ 166.2	$ 144.7	$ 106.5	$ 17.6
2019	$ 163.2	$ 155.5	$ 132.1	$ 89.5	$ (14.2)
2020	$ 152.3	$ 144.2	$ 119.2	$ 72.3	$ (47.2)

Q. UCAN uses CAISO 2010 Gridview runs in its analysis .[98] Did the CAISO use the 2010 Gridview information for the deferral analysis presented above?

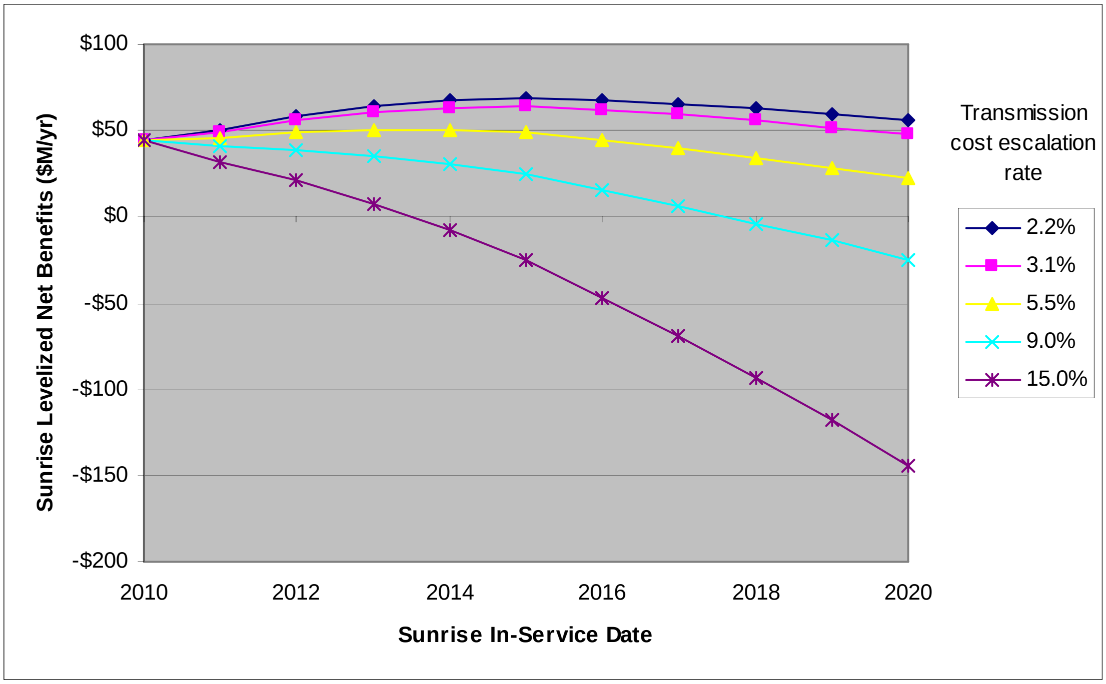
A. No. The CAISO uses the 2015 Gridview information for its deferral analysis presented above. This is consistent with the CAISO's April 20, 2007 testimony.

Q. Would the use of the 2010 Gridview <u>analysis materially</u> ~~results~~ alter the results presented above?

A. No. Figure 6 shows the results of using the 2010 Gridview energy-related benefits, and interpolating those benefits between 2010 and 2015. Benefits for years beyond 2015 continue to escalate at 2% per year. The figure reports the

[98] Marcus Confidential, 74.

same general findings those revealed in Figure 4: the highest net benefit occurs in 2015 instead of 2014~~2016~~ under UCAN's 3.1% escalation rate; and remains at 2010 under the 9% escalation rate. Similarly, Figure 7 shows that with the alternate RPS cost assumptions, the benefits of deferral remain small or negative, depending on the transmission escalation rate.



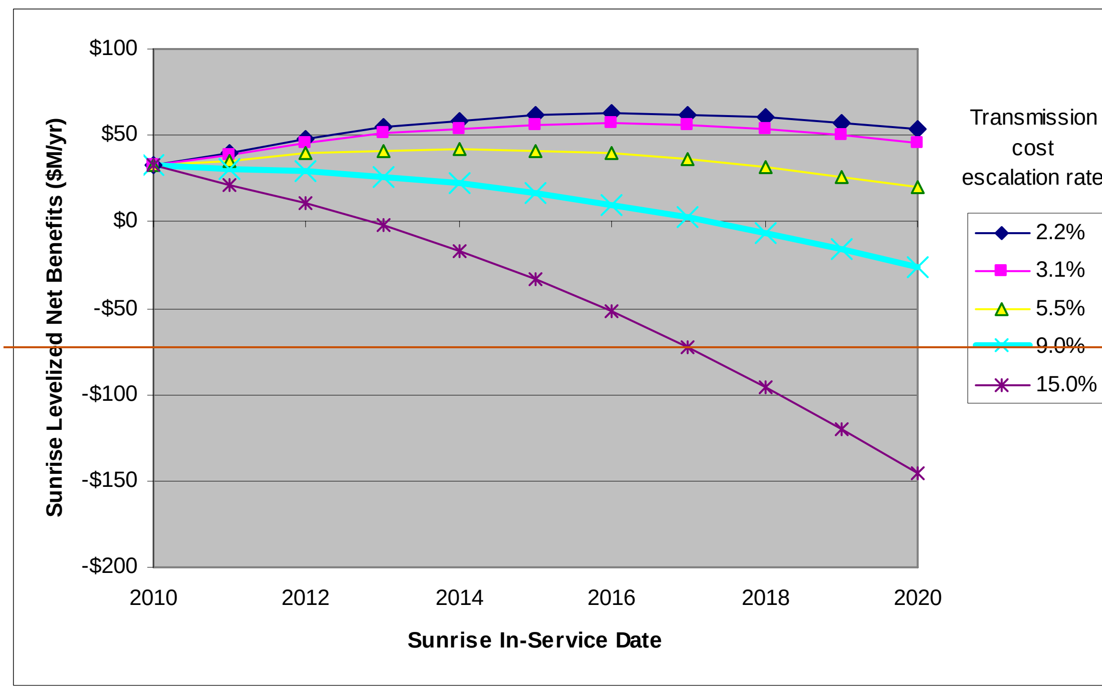
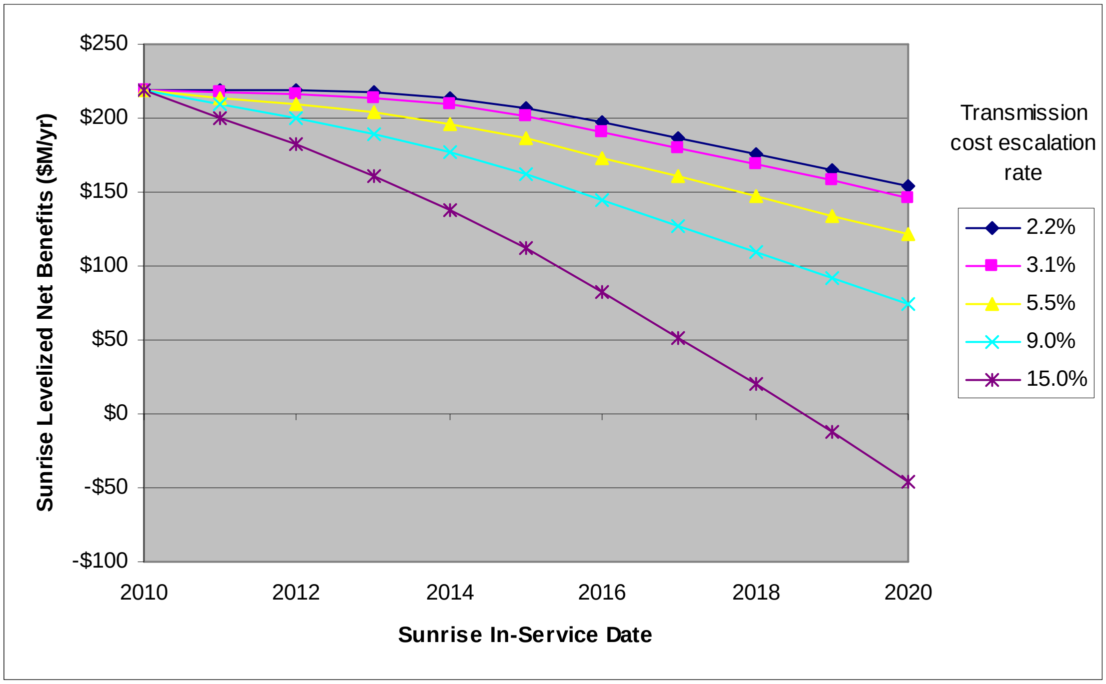


Figure 6: Levelized Net Benefits using 2010 Gridview and 4/20/07 RPS Costs

Table 9: Levelized Net Benefits - w/2010 Gridview and 4/20/07 RPS Costs ($Millions/yr)

	Transmission cost escalation rate				
	2.2%	3.1%	5.5%	9.0%	15.0%
2010	$ 44.0	$ 44.0	$ 44.0	$ 44.0	$ 44.0
2011	$ 50.5	$ 49.1	$ 45.7	$ 40.6	$ 31.9
2012	$ 58.0	$ 55.5	$ 48.8	$ 38.7	$ 20.7
2013	$ 63.7	$ 60.1	$ 50.4	$ 35.5	$ 7.5
2014	$ 67.6	$ 63.2	$ 50.7	$ 30.9	$ (7.7)
2015	$ 69.3	$ 64.0	$ 49.0	$ 24.5	$ (25.5)
2016	$ 67.9	$ 61.9	$ 44.5	$ 15.3	$ (46.8)
2017	$ 65.6	$ 58.9	$ 39.4	$ 5.7	$ (69.4)
2018	$ 62.9	$ 55.7	$ 34.1	$ (4.0)	$ (93.0)
2019	$ 59.6	$ 51.9	$ 28.6	$ (14.0)	$ (117.7)
2020	$ 55.4	$ 47.3	$ 22.3	$ (24.6)	$ (144.1)

	Transmission cost escalation rate				
	2.2%	3.1%	5.5%	9.0%	15.0%
2010	$ 32.6	$ 32.6	$ 32.6	$ 32.6	$ 32.6
2011	$ 40.1	$ 38.8	$ 35.3	$ 30.2	$ 21.5
2012	$ 48.4	$ 45.9	$ 39.2	$ 29.2	$ 11.2
2013	$ 54.5	$ 51.0	$ 41.3	$ 26.4	$ (1.6)
~~2014~~	~~$ 58.7~~	~~$ 54.2~~	~~$ 41.8~~	~~$ 22.0~~	~~$ (16.6)~~
2015	$ 61.3	$ 56.0	$ 41.0	$ 16.5	$ (33.5)
2016	$ 62.6	$ 56.6	$ 39.2	$ 10.1	$ (52.0)
2017	$ 62.1	$ 55.5	$ 35.9	$ 2.3	$ (72.8)
2018	$ 60.3	$ 53.1	$ 31.6	$ (6.6)	$ (95.5)
2019	$ 57.4	$ 49.7	$ 26.4	$ (16.2)	$ (119.9)
2020	$ 53.5	$ 45.4	$ 20.4	$ (26.5)	$ (146.0)



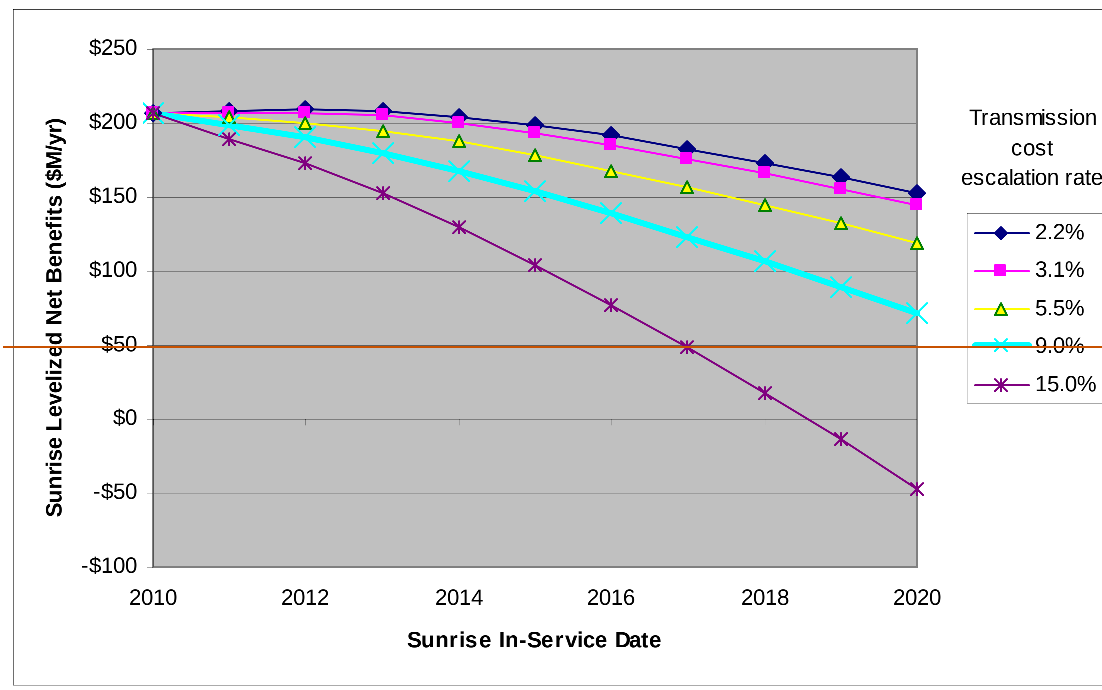


Figure 7: Levelized Net Benefits - w/2010 Gridview and Alternate RPS Costs ($Millions/yr)

Table 10: Levelized Net Benefits - w/2010 Gridview and Alternate RPS Costs ($Millions/yr)

	Transmission cost escalation rate				
	2.2%	3.1%	5.5%	9.0%	15.0%
2010	$ 218.5	$ 218.5	$ 218.5	$ 218.5	$ 218.5
2011	$ 218.8	$ 217.4	$ 214.0	$ 208.9	$ 200.2
2012	$ 219.3	$ 216.8	$ 210.1	$ 200.1	$ 182.0
2013	$ 217.5	$ 213.9	$ 204.2	$ 189.3	$ 161.3
2014	$ 213.4	$ 209.0	$ 196.5	$ 176.7	$ 138.1
2015	$ 206.8	$ 201.5	$ 186.5	$ 162.0	$ 112.0
2016	$ 196.8	$ 190.8	$ 173.5	$ 144.3	$ 82.2
2017	$ 186.5	$ 179.8	$ 160.3	$ 126.6	$ 51.5
2018	$ 176.0	$ 168.8	$ 147.3	$ 109.1	$ 20.2
2019	$ 165.4	$ 157.7	$ 134.3	$ 91.8	$ (12.0)
2020	$ 154.2	$ 146.1	$ 121.1	$ 74.2	$ (45.3)

	Transmission cost escalation rate				
	2.2%	3.1%	5.5%	9.0%	15.0%
2010	$ 207.2	$ 207.2	$ 207.2	$ 207.2	$ 207.2
2011	$ 208.4	$ 207.1	$ 203.6	$ 198.5	$ 189.8
2012	$ 209.8	$ 207.3	$ 200.6	$ 190.5	$ 172.5
2013	$ 208.3	$ 204.8	$ 195.1	$ 180.1	$ 152.2
~~2014~~	~~$ 204.5~~	~~$ 200.0~~	~~$ 187.6~~	~~$ 167.8~~	~~$ 129.2~~
2015	$ 198.8	$ 193.5	$ 178.5	$ 154.0	$ 104.0
2016	$ 191.6	$ 185.6	$ 168.2	$ 139.1	$ 76.9
2017	$ 183.0	$ 176.3	$ 156.8	$ 123.1	$ 48.0
2018	$ 173.5	$ 166.2	$ 144.7	$ 106.5	$ 17.6
2019	$ 163.2	$ 155.5	$ 132.1	$ 89.5	$ (14.2)
2020	$ 152.3	$ 144.2	$ 119.2	$ 72.3	$ (47.2)

Q. UCAN credits their 2018 Sunrise deferral case with an $8 million per year benefit from having more CTs for some years than if Sunrise were not deferred.[99] Do you agree that this adjustment is correct?

A. No, we do not. UCAN states that this adjustment is based on the CAISO's value of $51/kW-year for the energy benefits of a CT. The~~Unfortunately, the CAISO cannot match the footnote to any CAISO workpapers. Based on UCAN's description of the value, however, the~~ CAISO has determined to exclude that benefit in its deferral analysis for the following reasons:

- The CTs are not owned by SDG&E and its profits flow to third parties, thus not reducing the CAISO customer bills.

[99] Marcus Confidential, 76.

- Even if the CTs are owned by SDG&E, the post-Sunrise energy prices in San Diego could be relatively low because of the excess generation. Hence, a new CT in San Diego is unlikely to earn a profit that equals to $51/kW-year.
- If the new CTs are owned by SDG&E and they do not suppress the local energy prices, they would likely displace SDG&E's existing generation. The profit earned by the new CTs should be offset by the loss suffered by the existing generation.

4.5 SWPL II

Q. What is the CAISO's opinion on SWPL II?

A. The CAISO finds that SWPL does not violate applicable reliability criteria.[100] Thus, the CAISO concurs with the DRA that SWPL II is a feasible alternative to Sunrise.[101] However, the CAISO has not analyzed the economics of this alternative.

4.6 TE/VS

Q. What is the CAISO's opinion on TE/VS?

A. The CAISO opinion is as follows:

[100] The CAISO Initial Testimony, Part III, April 20, 2007, at 63.
[101] Zaninger, 6.

- As shown in Section 3, the CAISO finds TNHC's $126M reliability benefit estimate unreasonable. If this estimate were consistent with the CAISO's $63M level, the net benefit of TE/VS would be negative.[102]
- It appears that TNHC is attempting to insert a new alternative at this stage. Third parties had an opportunity to request that the CAISO study alternative scenarios; and the CAISO presented its results of the alternatives requested by interveners.[103]
- At the request of TNHC, the CAISO performed an analysis of Scenario TNHC1 LEAPS Project (i.e., CAISO Base Case modified by LEAPS), finding thermal reliability criteria violations.[104] By focusing on a standalone TE/VS, TNHC's testimony is a feeble attempt to distract the reliability issues related to the LEAPS Project.

5. Uncertainties

Q. What is DRA's proposal for handling uncertainties in Sunrise evaluation?

A. The DRA proposes a hybrid approach, which combines decision tree modeling, optimal dispatch, and stochastic simulation.[105]

Q. How has the CAISO dealt with uncertainties?

---

[102] Based on Auclair (p.33), the total benefit is $112M if the reliability benefit is $126M. Hence, the net benefit would be $49M if the reliability benefit became $63M (= $112M-63M). The line's cost is $51.3M. Hence the net benefit is -$2.3M (= $49M – 51.3M).
[103] The CAISO Initial Testimony, Part III, April 20, 2007.
[104] *Id.*, 68.
[105] Palmerton, K. Report on The Sunrise Powerlink, Phase 1 Direct Testimony, Volume 4 of 5, DRA, CPUC, May 18, 2007,.9 (Palmerton).

A. Under the CAISO's TEAM methodology, Sunrise's benefits are estimated for a given scenario, defined by numerous variables such as legislative and regulatory actions (e.g., LCR, RAR and RPS targets), the SSG-WI data base and its revisions by the CAISO, the forecasts of UDC loads, adjusted for the projected effects of demand-side-management and energy efficiency (DSM/EE), reliability-related payments and CT costs.[106] The CAISO recognizes the varying degrees of uncertainty inherent in these variables in each scenario, implying a potentially large spectrum of probable scenarios, each of which may realize with a differing likelihood.[107] To avoid overstating Sunrise's cost-effectiveness, the CAISO has estimated Sunrise's benefits using scenario assumptions that are conservative and likely result in some under-estimation of net benefits.

Examples of being conservative are illustrated by the following assumptions:

- Reliability benefit is driven by reasonably known impact of Sunrise on San Diego's local reliability compliance cost.
- The energy benefit is estimated using a low natural gas price forecast ($7/MMBTU) and relatively low locational differences in the costs of fuel between the desert southwest and CA ($.20 /MMBTU and reasonable load growth forecasts adjusted for DSM/EE/DR/rooftop solar and AMI induced price response programs.
- Sunrise's completion does not create a learning curve effect that can reduce renewable energy's per MWH cost in Imperial Valley.

---

[106] Initial Testimony of The California Independent System Operator Corporation, Part II, Application 06-08-010, April 20, 2007, red lined version, Section 2.
[107] *Id.*.7.

- There is no tightening of the GHG legislation either at the State or Federal level that can increase the value of renewable energy from the Salton Sea area.
- There is no large LMP differential across the WECC as a result of market power abuse and/or significant transmission congestion.[108]
- There is no consideration for Sunrise's option value in the benefit estimation.[109]

The CAISO could have substantially increased the estimated net benefits of Sunrise by altering anyone of the above assumptions. It has chosen not to do so to avoid overestimating Sunrise's benefit to the CAISO's customers.

Q. What is the CAISO's opinion on the DRA's hybrid approach?

A. As currently solved by the CAISO, the Sunrise evaluation problem is already a complicated one, entailing time-consuming and data-intensive modeling and computation. As an expert in transmission planning and operation, the CAISO knows resource planning under uncertainty. It has chosen to bypass the decision tree modeling and stochastic simulation, as suggested by the DRA, for two reasons. First, a decision tree cannot be reasonably represented if there are too many uncertain variables with unknown probabilities of realization (e.g., generation mix and expansion by year over different location in the WECC over a 40-year period). Second, even if the tree can be represented, its solution may only be driven by few likely key events (e.g., load and fuel forecast, RPS-compliance and reliability-compliance). Hence, the CAISO has taken the conservative

[108] The PV Devers II project was partially justified based on its ability to mitigate market power.
[109] This is notwithstanding of the DRA witness' suggestion to include the value, see Palmerton, .11.

approach to defining all input assumptions to develop a solid estimate of the low end of the net benefits range.

6. San Diego Grid Reliability Action Plan (SDGRAP)

Q. What is this plan?

A. The DRA proposes this plan to review "San Diego's local reliability needs every two years in a routine, integrated manner and identify and implement the likely best means for meeting such needs."[110] It suggests the plan to be implemented as part of SDG&E's regular Long-Term Procurement Plan (LTPP) cases.

Q. What is the CAISO's opinion on the DRA's proposal?

A. This proceeding has generated a large set of alternatives, ranging from generation-only solutions (e.g., repowering of South Bay plus new combustion turbines) to transmission-only solutions (e.g., Sunrise, Second Southwest Power Link). Nonetheless, the DRA believes that there are other options that merit further review.[111]

The CAISO has serious reservations about the potential for "paralysis by analysis" that could be triggered by the DRA's proposal. The reliability problem in the San Diego area is real and imminent. The CAISO would be remiss by searching for the cost savings from analyzing an infinite number of alternatives, precisely because inaction can lead to reliability deterioration, with significant outage cost consequences.

---

[110] Woodruff, 49.
[111] *Id.,* ES-6.

To be fair, the DRA "does recommend the Commission take steps to ensure that Sunrise's most critical purported objective – meeting local grid reliability needs in San Diego – is met in as timely and cost-effective a manner as possible."[112] But such steps are not an endless search for unrealistic or infeasible alternatives. Furthermore, the statewide long term transmission planning process that we described above provides a similar mechanism for studying the transmission needs of SDG&E.

Regardless of the outcome of this proceeding, the CAISO envisions an annual transmission planning process during which the very issue raised by the DRA can be considered. There simply is no need for duplicative studies that might lead to confusing results. The CAISO does not believe that the SDGRAP proposal should be adopted.

7. LEAPS Energy and ancillary service benefits

Q. What is the purpose of this section?

A. The purpose is to provide an estimate of LEAPS'(the pumped hydro storage facility) energy and ancillary service benefits. These benefits are used to determine the RMR payments to- LEAPS as a merchant plant, as well as determine benefits that would accrue to TAC participants if LEAPS were treated as a transmission asset. As described above, the CAISO recommends treating LEAPS as a merchant generator. As a merchant generator, the CAISO assumes

[112] *Id.*,t ES-8.

that LEAPS receives RMR payments equal to the costs of their plant, net of energy and ancillary services revenues received from market based sales.

Q. What is your estimate of the annual energy and ancillary services benefits of LEAPS?

A. Summarized in Table 11, the CAISO's estimate of annual energy benefits is $16.8 million and our estimate of the annual ancillary services benefits is $57.5 million. The total benefit is $ 74.3 million per year.

Table 11: Annual LEAPS Energy and Ancillary Service Benefits in 2010 Dollars

Energy Benefits	$ 16,819,360
Ancillary Service Benefits	$ 57,525,558
Total Benefits	$ 74,344,918

Q. How did you estimate the annual energy benefits?

A. The annual energy benefits are estimated as the sum of daily energy benefits. Daily energy benefits are equal to the revenue earned from selling energy into a wholesale market minus the cost of pumping. LEAPS can discharge at 500 MW for 12 hours, made possible by pumping at 600 MW for 12 hours. Pumping occurs during low-priced hours and discharge during high-priced hours. The facility thus yields an energy benefit on days when the price difference between high-priced and low-priced hours is larger than the per-MWh cost of energy lost by pumping.

We estimated the daily energy benefits using the CAISO's 2006 hourly average real-time energy and ancillary service prices for the SP15 congestion zone. We assumed that LEAPS would pump for twelve consecutive hours each day, and discharge for 12 consecutive hours each day. Given the monthly patterns of average hourly energy and ancillary service prices in 2006, Table 12 shows the most profitable operating schedules for LEAPS.

Table 12: Most Profitable LEAPS Operating Pattern by Calendar Month

Month	Pump Start Time	Pump Stop Time
January	05:00	17:00
February	06:00	18:00
March	02:00	14:00
April	07:00	19:00
May	02:00	14:00
June	02:00	14:00
July	01:00	13:00
August	01:00	13:00
September	23:00	11:00
October	23:00	11:00
November	23:00	11:00
December	00:00	12:00

Following the monthly schedules in Table 12, the hourly pumping cost for a given day is the hourly energy price during pumping hours for that day times LEAPS' 600 MW pumping load. Similarly, the hourly energy revenue for a given day is the hourly energy price for that day during discharge hours times LEAPS' 500 MW discharge capability.

Q. How did you estimate the ancillary services benefits of LEAPS?

A. We estimated the daily ancillary service benefits using the CAISO's 2006 hourly day-ahead ancillary service prices for the SP15 congestion zone. The hourly ancillary service revenues depend on whether LEAPS is pumping or discharging. When LEAPs is discharging, LEAPS can provide the relatively high-priced regulation down ancillary service. Because LEAPS is discharging at maximum capacity during all discharge hours in order to make energy sales, LEAPS is unable to increase its output and therefore cannot provide regulation up, spinning reserve or supplemental reserve services. The hourly ancillary service revenues while discharging are therefore the hourly regulation down price times LEAPS' discharge capability of 500 MW.

This estimate of AS value is consistent with LEAPS having variable speed drive pumps that allow it to provide all ancillary services while discharging, and up to 30%, or 180 MW while it is pumping. The hourly ancillary service revenues while pumping are the maximum of the regulation up, regulation down, spinning reserve and supplemental reserve prices times 180 MW.

Q. Does the monthly operating schedule listed in Table 12 consider hourly differences in ancillary service prices?

A. Yes, the monthly operating schedule listed in Table 2 maximizes total revenues during the month, including both energy and ancillary service revenues.

Q. Do you assume that LEAPS operates every day, regardless of the hourly price pattern?

A. No, we -do not. Instead, we assume that LEAPS does not operate on days when LEAPS' pumping costs would be greater than its energy and ancillary service revenues. Assuming that LEAPS operates every day would reduce the annual benefits by approximately $500,000.

Q. Can LEAPS provide any other benefits?

A. Yes, LEAPS could provide additional benefits such as black start, reactive support, wind firming, and over-generation mitigation. However, these benefits are difficult to quantify, are likely small relative to the energy and AS benefits described above, and could to some extent be provided by South Bay and other generators considered as alternatives to Sunrise. Moreover, if LEAPS is operated as a firming resource for wind power, its operation would no longer be optimized for energy and AS, as we assumed in calculating those benefits. Assigning additional value for wind firming would therefore require reducing the energy and AS benefits described above.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

I hereby certify that I have served, by electronic and United States mail, a copy of the foregoing Errata to the Rebuttal Testimony Submitted By The California Independent System Operator Corporation on June 15, 2007, to each party in Docket No. A.06-08-010.

Executed on July 12, 2007 at Folsom, California.

/s/Judith B. Sanders
Judith B. Sanders
Counsel
California Independent System Operator Corporation

SERVICE LIST FOR REBUTTAL TESTIMONY – A.06-08-010

ABBAS M. ABED
NAVIGANT CONSULTING, INC.
aabed@navigantconsulting.com

ANDREW B. BROWN
ELLISON, SCHNEIDER & HARRIS, LLP
abb@eslawfirm.com

G. ALAN COMNES
CABRILLO POWER I LLC
alan.comnes@nrgenergy.com

AUDRA HARTMANN
DYNEGY, INC.
Audra.Hartmann@Dynegy.com

PATRICIA C. SCHNIER
barbschnier@yahoo.com

BREWSTER BIRDSALL
ASPEN ENVIRONMENTAL GROUP
bbirdsall@aspeneg.com

Billie C. Blanchard
CALIF PUBLIC UTILITIES COMMISSION
bcb@cpuc.ca.gov

BRIAN T. CRAGG
GOODIN MACBRIDE SQUERI RITCHIE & DAY
bcragg@goodinmacbride.com

BONNIE GENDRON
bgendron@nethere.com

BRUCE FOSTER
SOUTHERN CALIFORNIA EDISON COMPANY
bruce.foster@sce.com

BRADLY S. TORGAN
CALIFORNIA DEPT. OF PARKS & RECREATION
btorgan@parks.ca.gov

CARRIE DOWNEY
HORTON KNOX CARTER & FOOTE
cadowney@san.rr.com

CAROLYN A. DORROH
RAMONA COMMUNITY PLANNING GROUP
carolyn.dorroh@cubic.com

CASE ADMINISTRATION
SOUTHERN CALIFORNIA EDISON COMPANY
case.admin@sce.com

LAUREL GRANQUIST
celloinpines@sbcglobal.net

CALIFORNIA ENERGY MARKETS
cem@newsdata.com

CENTRAL FILES
SAN DIEGO GAS & ELECTRIC
centralfiles@semprautilities.com

STEVE/CAROLYN ESPOSITO
cesposit@sdcoe.k12.ca.us

CLAY E. FABER
SOUTHERN CALIFORNIA GAS COMPANY
cfaber@semprautilities.com

CLARE LAUFENBERG
CALIFORNIA ENERGY COMMISSION
Claufenb@energy.state.ca.us

BRIAN KRAMER
colobiker@gmail.com

CONNIE BULL
conniebull@cox.net

PAUL RIDGWAY
cpuc@92036.com

CRAIG ROSE
THE SAN DIEGO UNION TRIBUNE
craig.rose@uniontrib.com

CAROLYN MORROW
GOLIGHTLY FARMS
Csmmarket@aol.com

DAHVIA LOCKE
COUNTY OF SAN DIEGO
Dahvia.Lynch@sdcounty.ca.gov

DAVID W. CAREY
DAVID CAREY & ASSOCIATES, INC.
dandbcarey@julianweb.com

DANIEL SUURKASK
WILD ROSE ENERGY SOLUTIONS, INC.
daniel@wildroseenergy.com

DARELL HOLMES
SOUTHERN CALIFORNIA EDISON
darell.holmes@sce.com

DAVID LLOYD
CABRILLO POWER I, LLC
david.lloyd@nrgenergy.com

DAVID BRANCHCOMB
BRANCHCOMB ASSOCIATES, LLC
david@branchcomb.com

DARRELL FREEMAN
ddfreeman@yahoo.com

DAVE DOWNEY
NORTH COUNTY TIMES
ddowney@nctimes.com

DENIS TRAFECANTY
COMMUNITY OF SANTA YSABEL & RELATED COMM
denis@vitalityweb.com

David Ng
CALIF PUBLIC UTILITIES COMMISSION
dhn@cpuc.ca.gov

DAVID HOGAN
CENTER FOR BIOLOGICAL DIVERSITY
dhogan@biologicaldiversity.org

DIANE I. FELLMAN
FPL ENERGY, LLC
diane_fellman@fpl.com

WILLIAM F. DIETRICH
DIETRICH LAW
dietrichlaw2@earthlink.net

DIANE J. CONKLIN
MUSSEY GRADE ROAD ALLIANCE
dj0conklin@earthlink.net

DAVID KATES
DAVID MARK AND COMPANY
dkates@sonic.net

DIANA LINSDAY
ANZA-BORREGO FOUNDATION & INSTITUTE
dlindsay@sunbeltpub.com

DAVID MARCUS
dmarcus2@sbcglobal.net

DONNA TISDALE
BOULEVARD SPONSOR GROUP
donnatisdale@hughes.net

Donald R. Smith
CALIF PUBLIC UTILITIES COMMISSION
dsh@cpuc.ca.gov

DAVID T. KRASKA
PACIFIC GAS AND ELECTRIC COMPANY
dtk5@pge.com

DON WOOD SR.
PACIFIC ENERGY POLICY CENTER
dwood8@cox.net

DAVID VOSS
dwvoss@cox.net

BOB & MARGARET BARELMANN
ecp9@roadrunner.com

J.A. SAVAGE
CALIFORNIA ENERGY CIRCUIT
editorial@californiaenergycircuit.net

ELIZABETH EDWARDS
RAMONA VALLEY VINEYARD ASSOCIATION
edwrdsgrfx@aol.com

LEGAL & REGULATORY DEPARTMENT
CALIFORNIA ISO
e-recipient@caiso.com

FREDERICK M. ORTLIEB
CITY OF SAN DIEGO
fortlieb@sandiego.gov

E. GREGORY BARNES
SAN DIEGO GAS & ELECTRIC COMPANY
gbarnes@sempra.com

GEORGE COURSER
gcourser@hotmail.com

JOHN&PHYLLIS BREMER
gecko_greens@juno.com

GLENN E. DROWN
gedrown@mindspring.com

EDWARD GORHAM
WESTERNERS INCENSED BY WRECKLESS ELECTRI
gorhamedward@cox.net

HENRY MARTINEZ
LADWP
Henry.Martinez@ladwp.com

MARY ALDERN
COMMUNITY ALLIANCE FOR SENSIBLE ENERGY
hikermomma1@yahoo.com

HARVEY PAYNE
RANCHO PENASQUITOS CONCERNED CITIZENS
hpayne@sdgllp.com

HENRY ZAININGER
ZAININGER ENGINEERING COMPANY, INC.
hzaininger@aol.com

IRENE STILLINGS
CALIFORNIA CENTER FOR SUSTAINABLE ENERGY
Irene.stillings@energycenter.org

JACK BURKE
CALIFORNIA CENTER FOR SUSTAINABLE ENERGY
jack.burke@energycenter.org

JUSTIN AUGUSTINE
THE CENTER FOR BIOLOGICAL DIVERSITY
jaugustine@biologicaldiversity.org

JASON YAN
PACIFIC GAS AND ELECTRIC COMPANY
jay2@pge.com

JEFFERY D. HARRIS
ELLISON, SCHNEIDER & HARRIS LLP
jdh@eslawfirm.com

JENNIFER PORTER
CALIFORNIA CENTER FOR SUSTAINABLE ENERGY
jennifer.porter@energycenter.org

JULIE L. FIEBER
FOLGER LEVIN & KAHN LLP
jfieber@flk.com

JALEH (SHARON) FIROOZ, P.E.
ADVANCED ENERGY SOLUTIONS
jfirooz@iesnet.com

JUDY GRAU
CALIFORNIA ENERGY COMMISSION
jgrau@energy.state.ca.us

HEIDI FARKASH
JOHN & HEIDI FARKASH TRUST
jhfark@pacbell.net

JIM BELL
jimbellelsi@cox.net

SERVICE LIST FOR REBUTTAL TESTIMONY – A.06-08-010

JOHN W. LESLIE
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
jleslie@luce.com

Joe Como
CALIF PUBLIC UTILITIES COMMISSION
joc@cpuc.ca.gov

JOSEPH M. PAUL
DYNEGY, INC.
Joe.paul@dynegy.com

JOSEPH RAUH
RANCHITA REALTY
joe@ranchitarealty.com

JUDITH B. SANDERS
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
jsanders@caiso.com

JUILE B. GREENISEN
LATHAM & WATKINS LLP
juile.greenisen@lw.com

KARL HIGGINS
HIGGINS & ASSOCIATES
karlhiggins@adelphia.net

KEN BAGLEY
R.W. BECK
kbagley@rwbeck.com

KEVIN WOODRUFF
WOODRUFF EXPERT SERVICES, INC.
kdw@woodruff-expert-services.com

KELLIE SMITH
SENATE ENERGY/UTILITIES & COMMUNICATION
kellie.smith@sen.ca.gov

W. KENT PALMERTON
WK PALMERTON ASSOCIATES, LLC
kent@wkpalmerton.com

GLENDA KIMMERLY
kimmerlys@yahoo.com

KAREN NORENE MILLS
CALIFORNIA FARM BUREAU FEDERATION
kmills@cfbf.com

KIM KIENER
kmkiener@cox.net

KEVIN O'BEIRNE
SAN DIEGO GAS & ELECTRIC COMPANY
ko'beirne@semprautilities.com

KEITH RITCHEY
kritchey@san.rr.com

Keith D White
CALIF PUBLIC UTILITIES COMMISSION
kwh@cpuc.ca.gov

Laurence Chaset
CALIF PUBLIC UTILITIES COMMISSION
lau@cpuc.ca.gov

DONALD C. LIDDELL
DOUGLASS & LIDDELL
liddell@energyattorney.com

LOUIS NASTRO
Lnastro@parks.ca.gov

LON W. HOUSE
WATER & ENERGY CONSULTING
lonwhouse@waterandenergyconsulting.com

LORRAINE A. PASKETT
LADWP
Lorraine.Paskett@ladwp.com

MICHAEL P. CALABRESE
CITY ATTORNEY'S OFFICE
mcalabrese@sandiego.gov

MICHEL PETER FLORIO
THE UTILITY REFORM NETWORK (TURN)
mflorio@turn.org

MICHAEL J. GERGEN
LATHAM & WATKINS LLP
michael.gergen@lw.com

MATTHEW JUMPER
SAN DIEGO INTERFAITH HOUSING FOUNDATION
mjumper@sdihf.org

MARY KAY FERWALT
mkferwalt@yahoo.com

MICAH MITROSKY
SIERRA CLUB
mmitrosky@sierraclubsandiego.org

MARC PRYOR
CALIFORNIA ENERGY COMMISSION
mpryor@energy.state.ca.us

MRW & ASSOCIATES, INC.
mrw@mrwassoc.com

Marcus Nixon
CALIF PUBLIC UTILITIES COMMISSION
mrx@cpuc.ca.gov

MICHAEL SHAMES
UTILITY CONSUMERS' ACTION NETWORK
mshames@ucan.org

MICHAEL S. PORTER
PACIFIC GAS AND ELECTRIC COMPANY
mspe@pge.com

MICHAEL L. WELLS
CALIFORNIA DEPARTMENTOF
PARKS&RECREATION
mwells@parks.ca.gov

Nicholas Sher
CALIF PUBLIC UTILITIES COMMISSION
nms@cpuc.ca.gov

NORMAN J. FURUTA
FEDERAL EXECUTIVE AGENCIES
norman.furuta@navy.mil

NANCY PARINELLO
nparinello@gmail.com

MICHAEL PAGE
oakhollowranch@wildblue.net

PETER SCHULTZ
OLD JULIAN CO.
oldjulianco@integrity.com

PAT/ALBERT BIANEZ
patricia_fallon@sbcglobal.net

DAN PERKINS
ENERGY SMART HOMES
perkydanp@yahoo.com

PAUL G. SCHEUERMAN
SHEUERMAN CONSULTING
PGS@IEEE.org

PHILIPPE AUCLAIR
philha@astound.net

CHRISTOPHER P. JEFFERS
polo-player@cox.net

PAM WHALEN
pwhalen2@cox.net

Robert Elliott
CALIF PUBLIC UTILITIES COMMISSION
rae@cpuc.ca.gov

RANDY S. HOWARD
LOS ANGELES DEPT. OF WATER AND POWER
randy.howard@ladwp.com

RORY COX
RATEPAYERS FOR AFFORDABLE CLEAN
ENERGY
rcox@pacificenvironment.org

AARON QUINTANAR
RATE PAYERS FOR AFFORDABLE CLEAN
ENERGY
rcox@pacificenvironment.org

REBECCA PEARL
ENVIRONMENTAL HEALTH COALITION
rebeccap@environmentalhealth.org

RICHARD W. RAUSHENBUSH
LATHAM & WATKINS LLP
richard.raushenbush@lw.com

RICHARD LAUCKHART
GLOBAL ENERGY
rlauckhart@globalenergy.com

EILEEN BIRD
sanrocky@aol.com

SARA FELDMAN
CA STATE PARKS FOUNDATION
sara@calparks.org

Steven A. Weissman
CALIF PUBLIC UTILITIES COMMISSION
saw@cpuc.ca.gov

SCOT MARTIN
scotmartin478@msn.com

SCOTT J. ANDERS
UNIVERSITY OF SAN DIEGO - LAW
scottanders@sandiego.edu

PAUL BLACKBURN
SIERRA CLUB, SAN DIEGO CHAPTER
sdenergy@sierraclubsandiego.org

SEPHRA A. NINOW
CALIFORNIA CENTER FOR SUSTAINABLE
ENERGY
sephra.ninow@energycenter.org

SUSAN FREEDMAN
SAN DIEGO ASSOCIATION OF GOVERNMENTS
sfr@sandag.org

Scott Logan
CALIF PUBLIC UTILITIES COMMISSION
sjl@cpuc.ca.gov

JOHN RAIFSNIDER
skyword@sbcglobal.net

SUSAN LEE
ASPEN ENVIRONMENTAL GROUP
slee@aspeneg.com

LARA LOPEZ
soliviasmom@cox.net

ARTHUR FINE
MITCHELL SILBERBERG & KNUPP LLP
sptp@msk.com

STEPHEN ROGERS
srogers647@aol.com

SUZANNE WILSON
swilson@pcta.org

TOM BLAIR
CITY OF SAN DIEGO
TBlair@sandiego.gov

Traci Bone
CALIF PUBLIC UTILITIES COMMISSION
tbo@cpuc.ca.gov

Terrie D. Prosper
CALIF PUBLIC UTILITIES COMMISSION
tdp@cpuc.ca.gov

THOMAS A. BURHENN
SOUTHERN CALIFORNIA EDISON
thomas.burhenn@sce.com

THOMAS ZALE
BUREAU OF LAND MANAGEMENT
Thomas_Zale@blm.gov

SERVICE LIST FOR REBUTTAL TESTIMONY – A.06-08-010

MICHAEL J. THOMPSON
WRIGHT & TALISMAN, PC
thompson@wrightlaw.com

TOM MURPHY
ASPEN ENVIRONMENTAL GROUP
tmurphy@aspeneg.com

Thomas Flynn
CALIF PUBLIC UTILITIES COMMISSION
trf@cpuc.ca.gov

EPIC INTERN
EPIC/USD SCHOOL OF LAW
usdepic@gmail.com

MARTHA BAKER
VOLCAN MOUNTAIN PRESERVE FOUNDATION
vmp@sbcglobal.net

VIDHYA PRABHAKARAK
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
vprabhakaran@goodinmacbride.com

VIDHYA PRABHAKARAN
GOODIN,MACBRIDE,SQUERI,DAY,LAMPREY
vprabhakaran@goodinmacbride.com

BILLY BLATTNER
SAN DIEGO GAS & ELECTRIC COMPANY
wblattner@semprautilities.com

RON WEBB
webron7@yahoo.com

WILLIE M. GATERS
williegaters@earthlink.net

OSA L. WOLFF
SHUTE, MIHALY & WEINBERGER, LLC
wolff@smwlaw.com

SHERIDAN PAUKER
SHUTE,MIHALY & WEINBERGER LLP
wolff@smwlaw.com

PHILLIP &ELIANE BREEDLOVE
wolfmates@cox.net

Scott Cauchois
CALIF PUBLIC UTILITIES COMMISSION
wsc@cpuc.ca.gov

SCOTT KARDEL
PALOMAR OBSERVATORY
WSK@astro.caltech.edu

JOETTA MIHALOVICH
11705 ALDERCREST POINT
SAN DIEGO, CA92131

KEVIN LYNCH
PPM ENERGY INC.
1125 NW COUCH ST., SUITE 700
PORTLAND, OR97209

JOHN GRISAFI
PO BOX 310125
GUATAY, CA91931

LINDA A. CARSON
ANZA-BORREGO FOUNDATION
PO BOX 2001
BORREGO SPRINGS, CA92004

WALLY BESUDEN
SPANGLER PEAK RANCH, INC
PO BOX 1959
ESCONDIDO, CA92033

WILLIAM TULLOCH
28223 HIGHWAY 78
RAMONA, CA92065

LYNDA KASTOLL
BUREAU OF LAND MANAGEMENT
1661 SOUTH 4TH STREET
EL CENTRO, CA92243