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)

SECOND ERRATA TO INITIAL TESTIMONY, PART II SUBMITTED BY THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON MARCH 1, 2007

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I. Introduction and Summary

On March 1, 2007, the California Independent System Operator (CAISO) submitted Part II of its Initial Testimony in this proceeding (March 1 Testimony). On March 23, 2007, the CAISO provided errata to that testimony to the parties. On March 27, 2007, the Commission sponsored a testimony workshop at which the parties were provided an opportunity to ask questions and make comments regarding the Part II testimony submission and the Errata.

Based on the input and suggestions of the parties, as well as the CAISO's evaluation of the alternative scenarios identified by the interveners, the Commission's Staff and the Aspen consultants, the CAISO has made additional modifications and corrections to its March 1 Testimony. This Second Errata presents those modifications and corrections described below:

(1) Update the (Green Path + LEAPS) transmission project costs. Based on comments at the March workshop, the CAISO reexamined the costs that it

has presented for the (Green Path + LEAPS) project. In this errata, the CAISO is correcting the costs for the Green Path North and LEAPS and the allocation of the Green Path North cost in the cost effectiveness analysis.

(2) Modification of the amount of combustion turbines (CT) needed in the San Diego area in the (Green Path + LEAPS) case. In the CAISO's March 1 Testimony, the (Green Path + LEAPS) project was estimated to yield a 565 MW reduction in the new capacity needed to maintain reliability in the San Diego area. Upon further analysis, the (Green Path + LEAPS) project is now estimated to reduce San Diego's CT need by only 500 MW.

(3) Change the reliability-must-run (RMR) operating cost computation so that the RMR operation costs vary directly with RMR contract capacity levels required. The annual payment is now equal to $60M/yr * (RMR contract capacity / 1440 MW), with a maximum of $60M/yr. The RMR contract capacity costs per kW were also changed for (Green Path + LEAPS) to have contract costs per kW that vary with the RMR contract capacity levels (the Sunrise case already used this relationship between capacity levels and price[1]).

In addition, the CAISO has taken this opportunity to make three small corrections and modifications, as listed below.

[1] The contract price is the recorded fixed cost payment for SDG&E escalated by 2% per year, then multiplied by the "% of Type 2 Cost." The "% of Type 2 Cost" rises linearly from 21% at an RMR contract capacity requirement of 680 MW to 100% at 1440 MW. The percentage is capped at 100%.

(4) Correct the clerical error related to the renewables portfolio standard (RPS) discussed in the 03/01/07 workpapers in note [6] to Table 4.5.

(5) Extend the ending year of the reliability benefit stream from 2043 to 2049, consistent with the other cost and benefit streams set forth in the CAISO's March 1 Testimony.

(6) Change the format of the tables in the CAISO's March 1 Testimony that add RPS benefits before subtracting transmission costs, so as to be consistent with the evaluation and results of the intervener requested studies.

Tables 1-3 below show the net results of all these changes on the CAISO's cost effectiveness analysis. Specifically:

- The first change increases the levelized cost of the (Green Path + LEAPS) transmission project (including the pumped storage facility) from \$193 million per year to \$205 million per year.[2] The updated transmission project cost is discussed in Section III below.
- The second change reflects the CAISO's re-examination of the (Green Path + LEAPS) alternative's impact on San Diego's import capability. The result of the updated analysis is that the (Green Path + LEAPS) case now is estimated to only reduce the San Diego area's CT need by 500 MW in 2015. This reduces the levelized reliability benefit for (Green Path + LEAPS) by \$8 million per year.
- In response to comments by UCAN at the March 27, 2007 workshop, the third change revises Sunrise's RMR benefits (i.e., operating cost savings). Based on Figure 1, the

[2] The CAISO believes that the full costs of network upgrades should also be included in the total transmission project cost, but such information cannot be publicly released at this time. The CAISO will update the total transmission costs for LEAPS when the information becomes available.

revised RMR operating benefit pattern reduces Sunrise's levelized RMR operating benefit by 3 million per year.[3] Similarly, the change reduces South Bay benefits by $1 million per year. The RMR operating cost change and the change in the RMR contract cost per kW increases the (Green Path + LEAPS) benefit by $5 million per year.

- Changes 4 and 5 increase Sunrise's levelized benefits by $5 million per year; South Bay by $2 million per year; and (Green Path + LEAPS) by $1 million per year.

Table 1: CAISO 2015

	Summary of 2015 Cost and Benefits	A	B	C	D	E	F	G
		Costs ($ millions per year, nominal)				**Net Benefits** (Base case cost - Alt. case cost)		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	13,893	13,786	13,847	13,856	107	46	37
2	Less CAISO congestion cost (reduces TAC)	(109)	(77)	(90)	(97)	(32)	(19)	(12)
3	Less URG Margin (reduces URG bal acct)	(4,188)	(4,158)	(4,167)	(4,180)	(30)	(22)	(8)
4	Less IOU excess loss payments	(713)	(699)	(708)	(705)	(14)	(5)	(8)
5	**Subtotal Energy Cost and Benefit**	8,883	8,851	8,882	8,873	**31**	**1**	**9**
6	RMR Capacity Payments	80	31	114	80	49	(34)	-
7	RMR Operating Payments	60	42	60	60	18	-	-
8	CT Capacity Costs	53	-	-	6	53	53	47
9	Transmission cost for new CTs	19	-	-	2	19	19	16
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	211	72	174	148	**138**	**37**	**63**
13	**Total Energy and Reliability Benefits**					**169**	**38**	**72**
	RPS Procurement Cost							
14	Adjusted RPS Cost	4,125	4,153	4,125	4,153	(28)	-	(28)
15	**Total Benefits**					**142**	**38**	**44**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	9.3	205.2	(157.0)	(9.3)	(205.2)
17	**Total Costs and Benefits**	13,218	13,234	13,190	13,379	**(15)**	**28**	**(161)**

[3] Note that levelized results are for the case where annual energy-related benefits are assumed to be constant in real dollars, based on the 2015 GridView analysis.

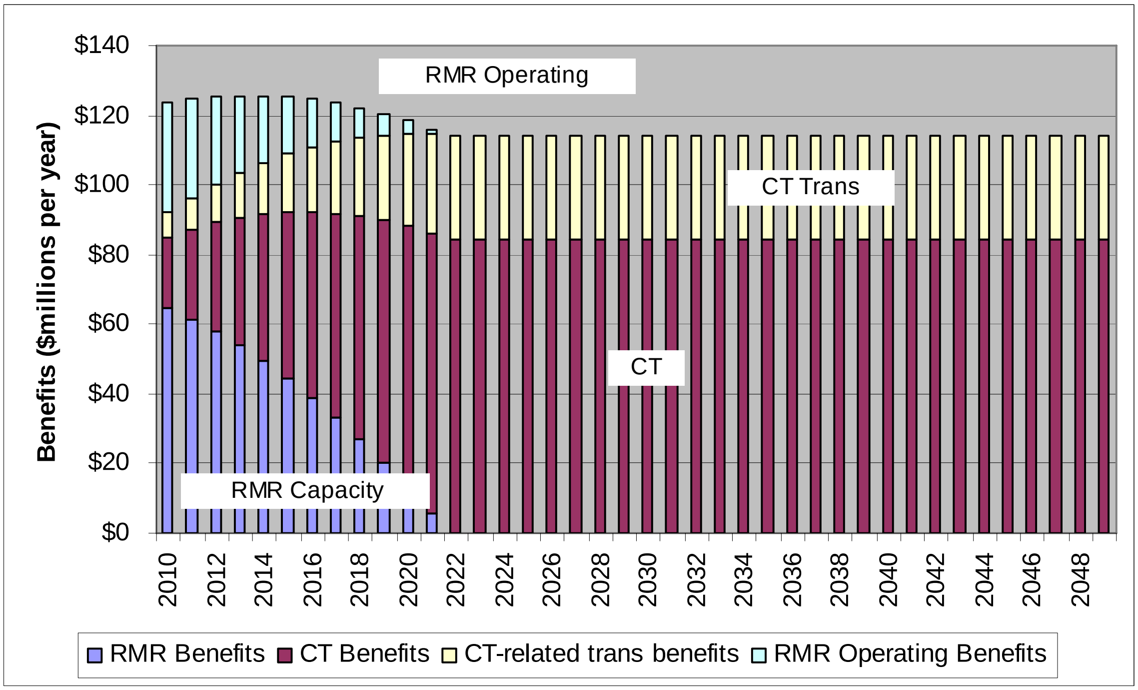
Table 2: CAISO 2020

	Summary of 2020 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	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,339	15,221	15,288	15,298	118	51	41
2	Less CAISO congestion cost (reduces TAC)	(120)	(85)	(99)	(107)	(35)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,624)	(4,591)	(4,600)	(4,615)	(33)	(24)	(9)
4	Less IOU excess loss payments	(788)	(772)	(782)	(779)	(15)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	9,807	9,773	9,806	9,797	**34**	**1**	**10**
6	RMR Capacity Payments	88	72	126	88	16	(38)	-
7	RMR Operating Payments	60	55	60	60	5	-	-
8	CT Capacity Costs	92	-	33	40	92	58	51
9	Transmission cost for new CTs	32	-	12	14	32	20	18
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	272	127	231	202	**144**	**41**	**70**
13	**Total Energy and Reliability Benefits**					**179**	**41**	**80**
	RPS Procurement Cost							
14	Adjusted RPS Cost	6,683	6,513	6,683	6,513	170	-	170
15	**Total Benefits**					**348**	**41**	**249**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	9.3	205.2	(157.0)	(9.3)	(205.2)
17	**Total Costs and Benefits**	16,762	16,570	16,729	16,718	**191**	**32**	**44**

Table 3: CAISO Levelized

	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	60	125	85	30	(35)	6
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	149	261	225	**149**	**37**	**73**
13	**Total Energy and Reliability Benefits**					**185**	**38**	**84**
	RPS Procurement Cost							
14	Adjusted RPS Cost	5,320	5,264	5,320	5,264	**56**	**-**	**55**
15	**Total Benefits**					**241**	**38**	**139**
	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	15,604	15,660	15,754	**84**	**29**	**(66)**

Figure 1: CAISO revised Sunrise reliability benefits



II. Reliability analysis for (Green Path + LEAPS)

The CAISO has re-examined the reliability analysis of the (Green Path + LEAPS) case, as extensively discussed at the March 27, 2007 workshop. In its March 1 testimony, the CAISO relied upon its own abbreviated reliability analysis and information shared by SDG&E during the February 2, 2007 Workshop to establish the local capacity requirements associated with the (Green Path + LEAPS*)* scenario. The CAISO analysis showed transient and post-transient stability problems with 3000 MW of San Diego imports, and SDG&E reported very large Network Upgrade costs associated with the LEAPS projects if it were to be used to reduce local capacity requirements. Based on that information, the CAISO determined that all existing generation would be needed to meet the San Diego area local capacity requirements. However, the 565 MW of new capacity required to maintain reliability between 2010 and 2015 would not be required.

Since the March 1 testimony, the CAISO has done further analysis on the local capacity requirements for the San Diego area if the LEAPs project were in-service. This analysis was performed at 2750 MW (additional 250 MW) and 3000 MW (additional 500 MW) of San Diego area imports with the Imperial Valley-Miguel 500 kV line out of service. The results of this analysis are discussed in more detail in the attached redline version of the March 1, 2007 testimony.

III. Transmission Cost Estimates

The CAISO's March 1 testimony focused on the calculation of economic benefits. While project cost estimates for each alternative were included in our estimates of net benefits, the CAISO did not perform an independent analysis of project costs. For the purposes of this Errata, the CAISO sought to verify the accuracy of the costs used in the March 1 testimony.

It was confirmed that SDG&E has not changed its estimate of the Sunrise project cost since its August 06 testimony. The CAISO has also confirmed that the costs of Southbay remain unchanged. However, in following up on the discussions at the March 27th workshop, the CAISO has updated the (Green Path + LEAPS) case's project cost estimates and has allocated only a portion of the Green Path's project cost to CAISO ratepayers based on an estimated share of the Green Path's capacity used by these ratepayers. In addition to the updated project cost estimates for (Green Path + LEAPS),the CAISO has also developed an allocation factor of 56.7% applied to the Green Path cost portion of this alternative. This factor reflects the CAISO's belief stated in its prior testimony and workshops that the use of Green Path facilities would not be free to CAISO ratepayers. The 56.7% is the CAISO's estimated share of the Green Path project cost to be paid by CAISO ratepayers, via wheeling charges for renewable resource procurement. It reflects the share of renewable energy, using capacity as a proxy that might be delivered to CAISO ratepayers through this line.

IV. Changes to the March 1 Testimony.

Attached to this Second Errata is a redlined version of the March 1 testimony in which the modifications set forth in the redlined version attached to the First Errata have been accepted, and the results of these modifications and updates are reflected as new redlines in the tables and narrative discussion.

Respectfully submitted,

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ATTORNEYS FOR THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR

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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)

INITIAL TESTIMONY OF THE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

PART II

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Dated: March 1, 2007

1. INTRODUCTION AND OVERVIEW

Q. Please state your names, titles, employer and qualifications.

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 Dr. Ren Orans, Managing Partner of Energy and Environmental Economics, Inc. (E3).

Q. On whose behalf are you submitting this testimony?

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

Q. Are you the same witnesses who sponsored Part I of the CAISO Initial Testimony filed on January 26, 2007 in this proceeding (01/26/07 testimony)?

A. Yes, we are. Our qualifications have previously been set forth at Attachment A to the CAISO 01/26/07 testimony.

Q. What is the purpose this Part II of the Initial CAISO testimony?

A. Our testimony aims to revise and resubmit all of the numbers in the 01/26/07 testimony, along with a full and transparent description of all assumptions used in the economic and reliability assessments of the four cases.[1] Dr. Orans'

[1] Based on the CAISO's January 8, 2007 Motion for Extension of Time to Complete Studies, these four plans are:

independent evaluation of the Sunrise economic assessments is also covered in this portion of the CAISO's initial testimony, as described at page 3 of the 01/26/07 testimony.

Q. Why is the CAISO modifying its 01/26/07 assessment?

A. The CAISO is modifying its 01/26/07 assessment in order to produce updated study results that provide the best possible foundation for comparing the CAISO's analysis of the Sunrise Project with third-party alternatives.

The CAISO's 01/26/07 assessment was the product of a combination of assumptions made by the CAISO, SDG&E, the Seams Steering Group – Western Interconnection (SSG-WI), and the CAISO South Regional Transmission Plan (CSRTP) study group. With the exception of the respective changes noted by SDG&E and the CAISO in their filings, the CAISO believed that SDG&E was using the same assumptions and database in their January 26, 2007 filing.

After reviewing the modifications submitted by SDG&E in Exhibit J attached to its Supplemental Testimony, however, the CAISO realized that SDG&E's testimony was based on data and planning assumptions that differed substantially from those utilized by the CAISO. In addition, the study results appeared to be quite sensitive to the modifications. Thus, the CAISO concluded that it was critical to review SDG&E's changes and update the data and

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- Updated Base Case
- Alternative 1: Sunrise
- Alternative 2: South Bay
- Alternative 3: (Green Path + LEAPS)

assumptions underlying the CAISO's January 26, 2007 testimony before developing third-party assessments of alternatives, such as those requested by UCAN.

This re-evaluation required the CAISO to review all of the assumptions in order to develop a common database to be used by the CAISO for its own analysis of Sunrise as well as for the studies requested by the third parties. This testimony describes the CAISO's proposed changes in the input assumptions and its basis for making these changes. Due to the extensive nature of these proposed changes, the CAISO has updated its assessment of the four cases described in its 01/26/07 testimony, and those updates are also covered in this testimony.

Q. What steps were undertaken by the CAISO in re-evaluating its assumptions and data points?

A. Based a full review of the materials filed by SDG&E in its Supplemental Testimony, the CAISO has completed the following tasks to date:

(1) We have revised the Base Case. This testimony documents the key changes, based on updated and reliable information, to the data file used in the 01/26/07 assessment. With its clearly laid out tables for the underlying resource plan and common input data, the revised Base Case is designed to achieve the following goals:

- To allow all parties to clearly see what the CAISO has done in forming the Base Case plan.

- To provide all parties the ability to determine whether the CAISO's Base Case is a reasonable representation and if necessary, to suggest revisions to the case's assumptions.
- To enable the CAISO to quantify how the cost-effectiveness results may vary with deviations from the Base Case's common input data (e.g., load forecast; natural gas price forecast; location, size and cost of renewable energy development; new generation resources' location, size and technology (e.g., combustion turbine (CT) vs. combined cycle gas turbine (CCGT)).[2]

(2) The CAISO has used updated information to repeat the analysis of the four cases in its 01/26/07 testimony. For the purpose of calculating the energy benefits associated with each plan, all four cases now meet the RPS goals. The Base Case of "No Sunrise" now includes 600 MW of geothermal resources added in the Salton Sea/IID area that the CAISO expects to be deliverable once Path 42 has been upgraded. We believe that Sunrise project facilitates the development of additional renewable resources in the Salton See/IID area, which our analysis indicates play a critical role in helping California utilities meet their RPS targets. Our cost-effectiveness analysis indicates that although the energy related benefits of Sunrise are probably small, they are still positive and the project does maintain the reliability of the San Diego area at a substantially lower cost than the base case. In addition,

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[2] Such deviations are already in SDG&E's 01/19/07 filing, as documented by Exhibit A in the CAISO's 01/26/07 Testimony.

based on the analysis completed to date, the Sunrise project has a greater levelized net benefit to California's electricity consumers than either South Bay Repowering or (Green Path + LEAPS).

(3) As described in its 01/26/07 testimony, the CAISO has conducted an analysis of the costs of RPS compliance, so as to inform all parties about the need for renewable energy development in the Salton Sea/IID area and its role in meeting RPS compliance targets.

Q. **Given what the CAISO has done to date, is Sunrise cost-effective?**

A. The cost-effectiveness results to be presented below indicate that the Sunrise project has a small negative net benefit of $-~~18~~ 15 million when compared to the base case in 2015 and a relatively large positive benefit of $~~205~~ 191 million in 2020. This pattern reflects increasing reliability and RPS related benefits over the first 10 years of the project. Our preliminary estimates of the levelized net benefits of Sunrise are $~~71~~ 84 million per year. The levelized benefits are composed of $~~181~~ 185 million in annual energy and reliability benefits and $~~58~~ 56 million in annual RPS benefits, while the levelized cost is $157 million per year.

Q. **How do the preliminary, levelized net benefits of Sunrise compare with the net benefits of the South Bay repowering scenario and the scenario with (Green Path + LEAPS)?**

A. The South Bay case has comparatively low energy and reliability benefits of $~~41~~ 38 million, and the same renewable mix as the Base Case so there is no RPS procurement benefit. After subtracting $9.3 million per year in transmission interconnection costs, the net benefit is $~~32~~ 29 million per year. The (Green Path + LEAPS) case has $~~83~~ 84 million per year in energy and reliability benefits and $~~57~~ 55 million in annual RPS procurement benefits. After subtracting $~~198~~ 205 million per year in transmission costs, the total net benefit is negative: ~~[~~-$~~58~~66~~]~~ million per year. These estimates do not include ancillary services benefits that might be provided by the LEAPS project and they assume that 56.7% of the full costs ~~and benefits~~ of ~~both LEAPS and~~ Green Path accrue to CAISO's ratepayers. For confidentiality reasons, the (Green Path + LEAPS) costs presented herein also exclude the full costs of network upgrades that would reduce the net benefit of the project.

Q. Are these findings indicative and preliminary?

A. Yes for two reasons. First, there is a potentially large set of feasible plans not yet considered by the CAISO and many uncertainties that have not yet been fully explored.

Second, the CAISO's analysis to date indicates that the Sunrise evaluation is a complicated integrated resource planning (IRP) problem, involving benefit estimates with varying degrees of uncertainty. A case in point is Sunrise's reliability cost savings based on reasonably known avoided costs for local generation and minimum load operation in San Diego. These cost savings estimates are much more certain than projected energy cost savings, which are sensitive to many input data assumptions, including (a) load forecasts by location; (b) natural gas price forecasts by location; and (c) forecasts of the size, location, and technology of new generation units dispersed over the vast Western Electricity Coordinating Council (WECC) area. ~~After completing all of the cases requested by third parties, we propose to investigate and summarize the impact of key sources of uncertainty on the cost effectiveness of both Sunrise's and the most promising alternatives to Sunrise.~~

Q. What is your overall conclusion?

A. The CAISO believes that Sunrise provides net benefits greater than those provided by South Bay, and (Green Path + LEAPS) in comparison to a single plausible Base Case plan. ~~However, additional work remains to be done. Once we have concluded our study of other parties alternative plans , we will provide a final analysis that reflects the consistent, plausible set of assumptions that we have developed for the study verification we have set forth in this testimony.~~

Q. How is the remainder of your testimony organized?

A. It is organized as follows.

Section 2 describes the CAISO's revised Base Case, with tables containing transparent assumptions regarding the underlying feasible resource plan.

Section 3 presents the CAISO's updated evaluation of the four cases listed in its 01/26/07 testimony.

Section 4 describes the CAISO's evaluation of renewable procurement costs under RPS for each of the four cases.

Section 5 describes the CAISO's reliability compliance analysis of each of the four cases.

Section 6 provides the CAISO's recommendations for going forward in the Sunrise evaluation.

2 REVISED BASE CASE

2.1 Definitions

Q. Please define a Base Case in an IRP study such as Sunrise.

A. We define a Base Case along two dimensions:

- A set of common input data that remain largely unchanged throughout the evaluation of all feasible plans considered in the study. In the Sunrise evaluation, the common input data includes load forecasts, natural gas price forecasts, existing and projected generation resources, including renewable energy sold to electricity consumers in California.
- A resource plan that serves as the default or reference option. This option is assumed to maintain sufficient amounts of local capacity by building combustion turbines (CTs) and signing capacity contracts to remedy San Diego's foreseeable reliability problem, while procuring enough renewable energy in the absence of new transmission.

This definition permits a cost comparison between the Base Case resource plan and its alternative, which may be Sunrise, South Bay, or (Green Path + LEAPS). An alternative plan is said to be cost-effective if it has lower cost than the Base Case plan. The net benefit of a cost-effective plan is the positive cost difference between the Base Case plan and the alternative plan at hand.

Q. Please define an alternative case.

A. A useful definition of an alternative case has the same two dimensions as the Base Case:

- A common set of input data that may differ from one in the Base Case. Relative to the Base Case, the difference may reflect a higher load forecast, a higher natural gas price forecast, or a lower projection of new generation resources.
- A feasible resource plan that may differ from the default option. For example, this plan may be Sunrise, South Bay, or (Green Path + LEAPS).

This definition allows all parties in this proceeding to distinguish the change in the Sunrise evaluation results as the consequence of (a) a change in the common input data assumptions; (b) a change in the set of feasible resource plans; or (c) a combination of (a) and (b).

Q. Please define the set of feasible alternatives.

A. It is a collection of feasible resource plans. A feasible plan achieves the RPS targets and meets the reliability criteria, given the common input assumptions. For example, the four cases in the 01/26/07 Testimony forms a limited set of feasible plans. To find the most cost-effective resource plan, however, it is necessary to analyze an expanded set of reasonably known alternatives, including those plans proposed by all parties who have requested the CAISO to analyze the proposed plans' economic and reliability performance.

2.2 Description

Q. Please describe the process used to revise the Base Case.

A. The CAISO revision of the Base Case began with a complete review of all of the data and assumptions used in its cost-effectiveness analysis for year 2015. This Base Case is built primarily from with the data and forecasts prepared by the SSG-WI. The SSG-WI's goal in developing this extensive database was to establish collaborative transmission expansion planning in the West. California electric utilities, the CEC, the CAISO and the CPUC have all supported and contributed to the development of SSG-WI data.

Using the latest SSG-WI database (August 2006) as a starting point, the CAISO, prior to its January 26th filing, made a number of modifications to the database to reflect better or more recent information. These modifications included:

- Replacement of generic California generation in the SSG-WI database with specific generation projects currently in its interconnection queue.
- Inclusion of resources in PG&E's service territory based on the utility's latest estimates of its new resources.
- Replaced the network configuration of the SSG-WI 2008 case with the power flow case used for reliability studies. Also added several transmission projects that SSG-WI added to the 2008 case.
- Inclusion of the Tehachapi transmission project approved by the CAISO board on January 25, 2007.

- In the January filing, the CAISO replaced a number of forecast new CTs located at Palo Verde with CCGTs. This testimony uses the original CT designation in the SSG-WI database
- Addition of the Path 42 upgrade based on the information supplied by IID to the CAISO.

For the reasons explained in Section 1, the CAISO has made the following additional changes:

- Inclusion of the Miguel transformer loading limit (currently in use, but not in the SSG-WI database).
- Modification of the SSG-WI gas prices to include gas transportation costs within California as a variable cost, rather than a fixed cost.
- Increase of the SSG-WI gas price for Arizona by 5.6% to reflect taxes on natural gas used by electric generators.
- Use of the CEC 2006 forecast of energy and demand for 2015 for all of California, with adjustments for roof top solar, and losses.
- Inclusion of 600 MW of geothermal in the Salton Sea/IID area in the Base Case because the Path 42 upgrade increases the area’s export capability by 600 MW.
- Inclusion of an RPS penetration of 26.5% by 2015 to make the reference case RPS-compliant. The 26.5% penetration is half way between the 20% target in 2010 and the 33% target in 2020.

- The Base Case also includes 20.2 TWh of incremental renewable energy (in addition to the renewable energy output previously identified in GridView) required to meet the 26.5% RPS target assumed for 2015. The locations and sizes of these resources are described below in Table 2.1.
- Addition of sufficient new transmission lines or upgrades to the existing system to accommodate the new renewable generation resources outside the Salton Sea/IID Area and avoid significant changes to the congestion of the existing transmission system.
- Explicit addition of CTs in the reliability analysis to capture the reduced losses from locating generation in the San Diego area. This lowers our estimate of CT capacity needed in San Diego compared to our January 26, 2007 testimony.

The CAISO review also resulted in the following computational changes:

- Refinement of its own reliability cost calculations based on a review of the SDG&E filing.
- Correction of the use of losses within the GridView model to eliminate double counting.
- Correction of the factors used to exclude non-TAC paying entities from the benefit calculations.

All database and assumptions changes are described in more detail in Table A1 in Appendix A to this testimony.

Q. **Is this process qualitatively different from the one used by SDG&E?**

A. No. SDG&E employed a similar process that begins with SSG-WI, CEC and CPUC information. SDG&E and the CAISO, however, differ in some of the adjustments made to some of these starting data sources. Also SDG&E's Base Case assumes 1,700 MW of geothermal generation and 900 MW of solar thermal new generation in the Salton Sea/IID area, whereas the CAISO assumes that only 600 MW of geothermal would be built absent the Sunrise or (Green Path + LEAPS) projects.

Q. **Please summarize the Base Case resource plan in the Base Case.**

A. Table 2.1 summarizes the CAISO's new Base Case plan. The first column of this table describes the generation and transmission resource additions. The second column describes the size of the resources and the third column describes why the resource is needed.

The refined Base Case resource plan differs from the CAISO's 01/26/07 Base Case primarily in the treatment of renewable resources. The 01/26/07 Base Case analysis did not explicitly model the siting and dispatch of new renewable resources in the GridView analysis. Table 2.1 shows that the new Base Case includes the explicit placement of new renewable resources throughout California and Nevada.

Table 2.1: Base Case resource plan for 2015

Resource	Size	Remark
Incremental CTs in San Diego	565 MW	Reliability compliance
RMR / capacity contract	1440 MW	Reliability compliance
Incremental renewable resources in the Salton Sea area	185MW geothermal previously identified in IID's resource plan. 600MW geothermal (added by CAISO)	Limited renewable energy development absent new transmission
Incremental renewable resources outside the Salton Sea area	433 MW biomass (distributed) 3940 MW Tehachapi wind 986 MW Solar thermal (NV border) 101 MW Altamont wind 1031 MW San Bernardino wind 6 MW East San Diego wind 560 MW Kern wind 298 MW Alameda wind 200 MW Solano wind 400 MW Sonoma geothermal 300 MW Colusa Lake wind 300 MW Modoc geothermal 300 MW Lassen wind 200 MW Shasta wind 350 MW Mono geothermal 500 MW Washoe (NV) geothermal 40 MW Colusa geothermal	Incremental means above the resources already identified in the SSG-WI database.
Transmission to accommodate incremental renewable resources outside of Salton Sea area.	Added New Transmission Capacity 1000 MWs Northeast California 740 MWs Sonoma/Lake/Colusa 756 MWs Alameda/Solano 4500 MWs Tehachapi 4580 MWs San Bernardino /Mono 750 MWs San Diego 1775 MWS CA – Distributed	Transmission added into GridView to facilitate renewable generation without a significant increase in congestion.
Sunrise transmission project	No	Alternative plan in Case 2 described in Section 3
Repowering South Bay	No	Alternative plan in Case 3 described in Section 3
Green Path + LEAPS	No	Alternative plan in Case 4 described in Section 3

2.3 Review of the Base Case's key assumptions

2.3.1 Natural gas price forecast

Q. Have you reviewed the natural gas price forecasts by region used by SSG-WI?

A. Yes, and we believe that the forecast is reasonable, but could be improved by adding adjustments for local distribution charges in California and by adding a gas tax in Arizona.

Q. Please describe your review.

A. Our review begins with Exhibit A of the CAISO Testimony, which states on p.11 that the CAISO's 2015 fuel price assumption is based on a $7.00/MMBtu price for Henry Hub delivery. The related SoCal natural gas price is assumed to be $6.89/MMBtu (Exhibit A, Table A-7, p.11), with a $0.20/MMBtu price differential between SoCal and Arizona. Thus, our review aims to answer the following two questions: (1) Is the $6.89/MMBtu SoCal price forecast reasonable? and (2) Is the $0.20/MMBtu locational price differential a conservative assumption?

Q. Is the $6.89/MMBtu SoCal price forecast reasonable?

A. We find this forecast reasonable for the following reasons:

- The NYMEX natural gas futures prices on 01/31/2007 for monthly Henry Hub delivery has average annual values of $7.39/MMBtu in 2010 and $6.87/MMBtu in 2012 - the furthest year for which natural gas futures are currently traded. These values corroborate the SSG-WI's assumption and the CAISO's use of a $7.00/MMBtu Henry Hub price in 2015.
- The NYMEX reports the SoCal Gas basis swap price of -$0.31/MMBtu for 2010, implying a SoCal Gas natural gas price of $7.08/MMBtu (= $7.39 - $0.31) in 2010. The SoCal Gas basis swap price for 2012 is -$0.22, implying a SoCal Gas price of $6.65/MMBtu (= $6.87 - $0.215) in 2012. These values corroborate the CAISO's assumption of a $6.89/MMBtu SoCal Gas natural price in 2015.
- The Commission's 12/14/06 Draft Resolution on Market Price Referent (Appendix B, p.18) adopts $6.83/MMBtu as the 2015 natural gas price forecast for electric generators in California.[3]
- The Energy Information Administration (EIA), in the Supplemental Tables to its 2006 Annual Energy Outlook, published in February 2006, forecasts the 2015 price of natural gas delivered to electric generators in the Pacific Region to be $7.41/Mcf.

Q. Is the $0.20/MMBtu locational price differential used in the SSG-WI database a conservative assumption?

[3] Draft Resolution E-4049, December 14, 2006, CPUC CA: San Francisco.

A. Yes, based on an examination of basis swap prices. NYMEX publishes settlement prices for natural basis swaps between Henry Hub and various points in North America, including SoCal Gas through December 2010. NYMEX does not provide settlement prices for natural gas delivered directly in Arizona. However, NYMEX does provide settlement prices for three nearby natural gas supply basins: San Juan in Southwestern Colorado (through December 2009), Permian in eastern New Mexico/West Texas (through December 2009), and Waha in West Texas (through December 2010).

A basis differential between SoCal Gas and a supply basin is determined by subtracting the supply basin basis swap price from the SoCal Gas basis swap price. The 01/31/07 NYMEX Henry Hub price and the basis swap prices for the four locations in 2009 and 2010 corroborate the CAISO's assumption of a $0.20/MMBtu basis differential between Arizona and SoCal Gas.[4]

As a second check, the EIA's Annual Energy Outlook 2006 also forecasts natural gas prices delivered to electric generators in the Rocky Mountain region, including New Mexico and Arizona. EIA's 2015 price is $6.74/Mcf, implying a

[4] The computation of basis differential is given in the table below:

Variable	Price ($/MMBtu)	
	Year 2009	Year 2010
NYMEX Henry Hub price	$7.75	$7.39
SoCal Gas Basis Swap price	($0.30)	($0.31)
San Juan Basis Swap price	($0.72)	N/A
Permian Basis Swap price	($0.60)	N/A
Waha Basis Swap price	($0.47)	($0.47)
San Juan – SoCal basis differential	$0.43	N/A
Permian – SoCal basis differential	$0.30	N/A
Waha – SoCal basis differential	$0.17	$0.15

basis differential of $7.41 – 6.74 = $0.67/Mcf or $0.65/MMBtu (using a conversion factor of one Mcf = 1.03 MMBtu).

Q. What are the natural gas price adjustments that you have incorporated in your cost-effectiveness analysis?

A. First, we have incorporated a transportation adder for gas delivered to generators in California. The CAISO's natural gas price forecasts used in its 01/26/07 testimony reflect the commodity price only, consistent with the Commission's practice in making the natural gas price forecast for the Market Price Referent.[5]

However, generators in California pay for intra-state transportation of natural gas transportation. The rate for Firm Intrastate Transmission Service, listed in SoCal Gas Schedule GT-F, is currently $0.3892/MMBtu for generators using 3 million therms or more per year. Schedule GT-F also lists an Interstate Transition Cost Surcharge of -0.033¢/therm (-$0.0033/MMBtu), and Schedule G-SRF lists a "Surcharge to Fund Public Utilities Commission Utilities' Reimbursement Account" of 0.076¢/therm ($0.0076/MMBtu). Totaling these charges, the CAISO adds $0.3935/MMBtu to its wholesale natural gas price forecast of $6.89/MMBtu for southern California,[6] resulting in a revised forecast of $7.28/MMBtu in year 2015. Similarly, the CAISO adds $0.1651/MMBtu to the gas price forecast for PG&E's service territory to reflect the tariff G-EG and G-SUR for electric generators purchasing natural gas at the backbone system.

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[5] Draft Resolution E-4049, December 14, 2006, CPUC CA: San Francisco.
[6] The SDG&E charges are the same as those reported here.

Q. What is the second natural gas price adjustment that have you incorporated into this testimony?

A. We have increased the cost of natural gas in Arizona to reflect the tax that electric generators located in Arizona must pay on their natural gas purchases. The tax is 5.6%, so we increased the SSG-WI natural gas price in Arizona by that rate.

2.3.2 Load forecasts

Q. Have you reviewed the load forecasts in Table 2.1?

A. Yes. The CAISO is using the CEC's most recent forecast for all California utilities, adjusted for roof top solar and losses. The CEC sales forecast (unadjusted for roof top solar) shows statewide growth levels of 1.2% per year for 2006 through 2015, and 1.1% per year for 2006 through 2020. In contrast, the San Diego rate is higher at 1.5% per year and 1.4% per year, respectively, but still reasonable. We opine that the CEC forecasts are the most recent information available, suitable for developing a Base Case that is unbiased with respect to Sunrise or other alternatives being considered in this proceeding.

2.3.3 Reliability cost

Q. Has the CAISO revised its methodology for calculating reliability costs?

A. Yes. Motivated by the discussions at the 02/08/07 and 3/27/07 public workshops in San Diego, our review of SDG&E's reliability analysis has led to several changes to our reliability costs estimate for each resource plan.

First, we have re-run our reliability analysis of the San Diego area to determine the amount of new CT capacity that would be required to meet reliability criteria in 2015. By explicitly placing CTs in the load flow model, the estimated MWs of needed new CTs is now lower than the CAISO's previous analysis because of lower losses.

Second, instead of treating all RMR payments as fully compensating generators for all fixed and variable costs, as currently reflected in existing Type 2 contracts, the CAISO believes that the substantial import capability provided by Sunrise would result in lower payments to some generators. Future capacity contracts are expected to be priced in a competitive procurement auction. The auction will set higher capacity prices when there are shortages and lower prices when there is excess supply. This pattern of capacity pricing mimics Type 1 capacity payments during periods of excess supply, and Type 2 capacity payments when there are capacity shortages. Hence, the CAISO made the following capacity payment assumptions:

- For the Base Case and South Bay cases, in which there is not expected to be a significant surplus of excess capacity, contracts are viewed as Type 2 contracts, under which the generator is paid its full capacity cost, with the profit from energy sales going to the contract buyer.

- For the Sunrise case, which causes a surplus of excess generation capacity beyond the avoidance of the 565 MW of CTs required in the Base Case, the CAISO treats the capacity contracts like the Type 1 contracts. Under a Type 1 contract, the generator receives a lower capacity payment, but it keeps any profit it makes on energy sales.
- For the (Green Path + LEAPS) case the CAISO ~~assumed~~ determined that the project would avoid ~~the need to add an estimated 565~~ 500 MW of CT's that are required in the Base Case in 2015~~,~~. ~~but would not reduce t~~The RMR capacity requirement met by existing generators in the area would be 1440MW in 2015, the same as the Base Case.

Finally, the CAISO has estimated additional operating costs associated with the RMR plants that are not captured in the Gridview runs. These costs reflect pre-dispatch costs for RMR units in San Diego. RMR units are predispatched for local reliability needs (prior to real-time). All RMR units receive a ~~variable~~ "predispatch" cost payment for energy provided under the RMR contract option, which is paid as the difference (if any) between the unit's variable operating costs and market revenues received for energy provided in response to an RMR requirement.

~~Pre-dispatch costs are the variable cost payment for predispatched energy provided under the RMR contract for the amount which is paid as the difference (if any) between the unit's variable operating costs and market revenues received for the same energy.~~ Because of the complexity of forward predispatch requirements, these requirements were not included in the Gridview model. We have assumed a share of these costs can be avoided with increased import capability.

Q. Did you model the reliability costs in only one year or over multiple years?

A. We modeled reliability costs for 40 years beginning in 2010. We performed a multi-year analysis to capture the effects of growth on the reliability costs. We chose 40 years to be comparable to the service life of the transmission projects. To be consistent with the other cost estimates, we calculate reliability costs for 2015, 2020 and levelized over 40 years.

Q. How did you model the costs of CTs needed for reliability?

A. CT costs are the MWs of required new CTs, priced at a unit cost of $78/kW-year (2006 dollars). In all cases the nominal unit cost of the CT capacity is increased by 2% each year to reflect inflation.

The required MWs of new CTs are based on the 2015 reliability power flow analyses. The required MWs for other years are computed as follows:

- For the Base Case, 565 MW of CTs are needed in 2015. That required capacity is reduced by the projected load growth of 65 MW/year for each year prior to 2015, and increased by 65 MW for each year after 2015.
- For the Sunrise case, there is 435 MW (1000 MW of import capability less 565 MW of imported capacity from renewables) of excess transmission

import capability in 2015. Therefore, there are no CTs added until 2022 when the 65 MW/year load growth "consumes" the excess import capability. In 2022, 20 MW of CT capacity is added; and 65 MW of CT capacity is added each year thereafter.

- For the South Bay case, there are no new CTs in 2015 or prior, but 65 MW of new CT capacity is added in 2016 and each year thereafter.
- For the (Green Path + LEAPS) case, ~~the CT requirement is~~ 65 MW of new CT capacity is added in 2015 and each year thereafter. ~~the same as the South Bay case.~~

Q. Did you include the cost of transmission that could be required to interconnect the new CTs?

A. Yes. We added annual transmission cost equal to 35.2% of the CT cost in each year. The 35.2% value is the ratio of the transmission to the generation revenue requirements shown in Table A-7 of the joint CAISO and SDG&E Exhibit A from the CAISO's January 26, 2007 testimony.

Q. What are the reliability benefits related to avoided CTs and CT-related transmission?

A. A comparison of the CT and CT-related transmission costs of the Base Case and the alternative cases yield the following levelized benefits over 40 years: $~~75~~ 107 million per year for Sunrise, $~~51~~ 73 million per year for South Bay, and $~~51~~ 66 million per year for (Green Path + LEAPS).

~~Since all three alternatives provide sufficient capacity to eliminate the need to construct new CTs prior to 2015, the benefits in 2015 (nominal dollars) are the same $53 million per year for all three alternatives.~~

~~The benefits in year 2020 (nominal dollars) are: $92 million per year for Sunrise, $58 million per year for South Bay, and $58 million per year for (Green Path + LEAPS).~~

These ~~values~~ Sunrise benefits are higher than those in the CAISO 01/26/07 testimony because that testimony only considered a single year, 2015. In that testimony, the Sunrise line was estimated to avoid 711 MW of CT capacity. But Sunrise will have 1,000 MW of capacity over time as load grows and San Diego needs additional capacity. Hence, the 01/26/07 assessment understates the total lifecycle avoided CT costs from the project because it only considers the single year value avoided CT costs in 2015.

To confirm the reasonableness of the new results, consider that the cost of a CT is $78/kW-yr in 2006 dollars. Ignoring inflation, but increasing the value for interconnection costs brings the value to $105/kW-yr. The Sunrise case adds 1000 MW of import capability. The 1000 MW of avoided CTs results in approximately $105 million per year of capacity related benefits (= 1000 MW * about $105/kW-yr).

Q. How do you model RMR costs in your updated analysis?

A. There are two parts to the RMR costs, the variable payment and capacity payment. The variable payment is based on recorded pre-dispatch payments to existing RMR generators. The capacity payment is the annual RMR requirement for San Diego multiplied by the capacity price.

Q. Please describe how you use ~~the~~ RMR operating cost ~~pre-dispatch payment~~ in your analysis.

A. The annual RMR operating benefit is the difference between the RMR operating costs in the Base Case and the alternate cases. The RMR operating costs vary directly with the RMR contract capacity levels. The annual payment is modeled as $60M/Yr * (RMR capacity requirement / 1440MW), with a maximum of $60M/yr. ~~The pre-dispatch costs for each case are as follows.~~

~~Base Case. Pre-dispatch payments are constant in nominal dollars for all years ($60 million per year).~~

~~Sunrise: Pre-dispatch costs are 75% of the Base Case cost, based on the expectation that 2 RMR units (1/4th of the RMR units) would not require pre-dispatch payments ($45 million per year).~~

~~South Bay: Pre-dispatch costs are only slightly lower than the Base Case ($55 million per year).~~

~~(Green Path + LEAPS): Same as the Base Case ($60 million per year).~~

Q. How did you determine the RMR capacity in each year for each case?

A. The required MW of RMR are based on the 2015 reliability power flow analyses.

- For the Base Case, all 1,440 MW of in-area generation is needed for RMR in 2015. Because of the magnitude of the import deficiency, 1,440 MW of RMR is also needed in all years before and after 2015.
- For the Sunrise case, only 1,005 MW of RMR capacity is needed in 2015. The RMR requirement is 65 MW less each year prior to 2015, and increases by 65MW each year after 2015. The RMR capacity requirement for existing generators reaches 1440 MW in 2022 and remains the same thereafter.
- For the South Bay case, the total RMR capacity for 2015 is 2060 MW, all of which will be needed to meet reliability criteria. However, for years prior to 2015, the RMR capacity requirement is lowered by 65 MW each year.
- For the (Green Path + LEAPS) case, the RMR capacity requirement is 1440 MW in ~~2015~~ 2014 and beyond. The RMR requirement is 65 MW less each year prior to ~~2015~~2014.

Q. How did you determine the capacity price for the RMR contracts?

A. The CAISO has modeled the two current types of RMR capacity payments to reflect the varying payment levels that may be required during the study period. As noted above, a Type 1 contract offers a relatively low capacity payment, while a Type 2 contract provides a relatively high capacity payment.

For the Type 2 contract price, the CAISO started with average actual 2005 RMR fixed payments to Type 2 generators in the SDG&E zone. This value was then escalated by inflation at 2% per year.

For the Type 1 contract price, the CAISO assumes that the payment level would be no higher than the Type 2 payments in the presence of transmission import capability in excess of in-area CT displacement. ~~Accordingly, the Type 1 payments only apply in the Sunrise case that assumes a 2010 in-service date for the new transmission.~~ For year 2010, the CAISO assumes that the new import capability in the Sunrise case would reduce the Type 1 capacity payment to about 21% of the Type 2 level, based on a minimum payment of $10.72/kW-yr[7] in 2010 to cover the cost of fixed O&M for a CT. In year 2022, the Type 1 contract price is assumed to be 100% of the Type 2 level, as the average demand growth of 65 MW per year would exhaust the import capability of the new transmission project. For the years between 2010 and 2022, we assume that the annual Type 1 price can be found by linear interpolation.

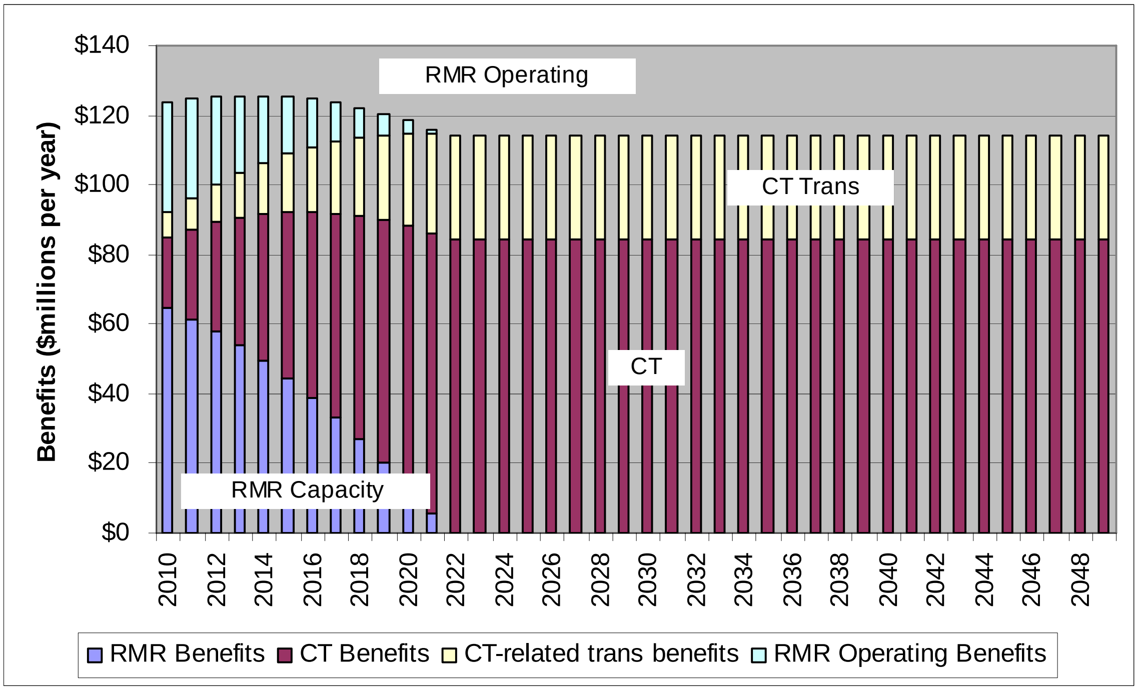
For the (Green Path + LEAPS) case, Type 1 contract prices would also apply in the years prior to 2014 because of available transmission import capability in those years. The (Green Path + LEAPS) contract prices use the same relationship between import capability and price as the Sunrise case.

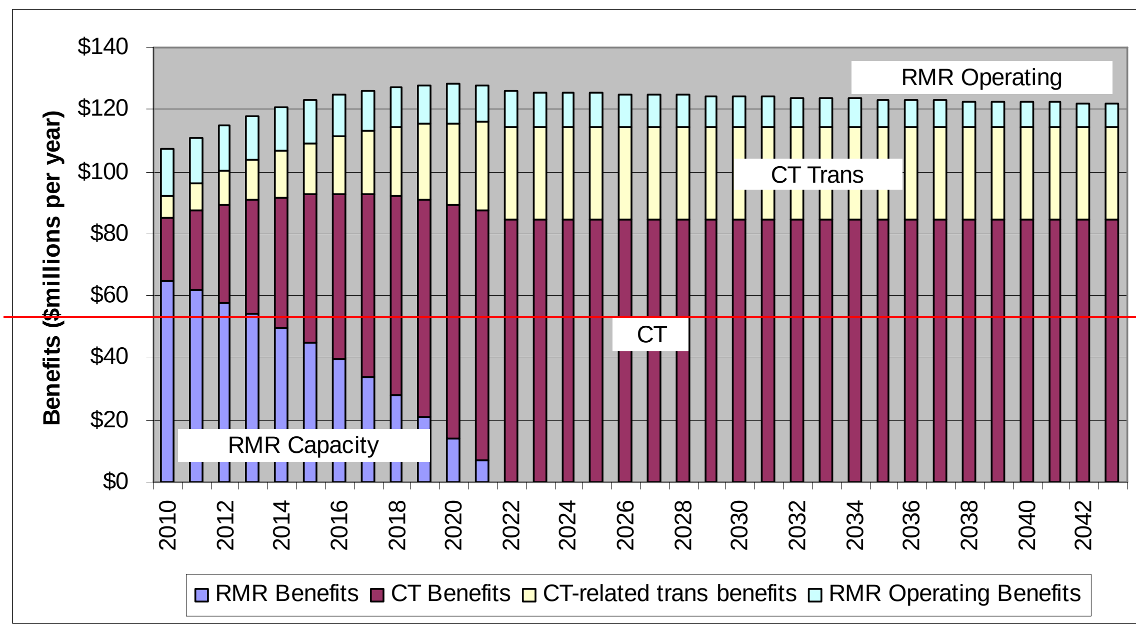
Q. How do the reliability benefits change over the years for the Sunrise case?

[7] From the EIA Energy Outlook 2005

A. The annual reliability benefits are shown in constant dollars in Figure 2.1. The RMR capacity and operating benefits decline rapidly as the quantity of RMR contract capacity with existing generation approaches the 1440 MW limit~~,~~. As contract capacity increases, ~~and~~ the price of that capacity approaches the full Type 2 price level and the RMR operating cost payments also approach the base case level. CT and CT-related transmission benefits rise in the early years, but then they level out in 2022 when CT capacity is being added at the same rate in both the Sunrise and the Base Case. RMR operating payments decline slowly in real terms because of our assumption to hold them constant in nominal dollars.

Figure 2.1: Annual Reliability Benefits for Sunrise relative to the Base Case (Constant 2010 dollars)





Q. What are the total reliability benefits of RMR Capacity, CT capacity, CT-related transmission, and RMR operating costs in 2015 and 2020?

A. The total reliability benefits for the three cases are listed below. All values are in millions of nominal dollars.

- Sunrise: 2015: $~~136~~ 138 2020: $~~156~~144
- South Bay 2015: $~~42~~37 2020: $~~46~~41
- (Green Path + LEAPS) 2015: $~~71~~63 2020: $~~79~~70.

2.3.4 Gridview modeling of RPS compliance

Q. How did you determine the amount of renewable resources needed under the Base Case and the alternative plans?

A. As stated previously, all of our cases are RPS compliant. RPS compliance is defined as having sufficient renewable GWh to be compliant with the statutory targets for 2010 and 2020 for California electricity consumers as a whole. In addition to the participation of IOUs loads (including unbundled Direct Access load within the IOU service territories), we assumed that 75% of the Publicly Owned Utility load also complies with these goals. Based on these assumptions, the total amount of renewable energy need to meet RPS targets is expected to be approximately 79.6 TWh/year in 2015 and 104.4 TWh/year in 2020.

Q. How much renewable energy did you incorporate into your Gridview analysis?

A. The updated SSG-WI data already included approximately 22.5 TWh/year of solar, wind, and geothermal renewable generation serving California loads today. In addition to this renewable generation, the CEC estimated that 2005 renewable generation from small hydro and biomass resources in California would total 10.8 TWh/yr. These small hydro and biomass resources are frequently connected to lower voltage facilities that are below the voltage level analyzed by GridView. Therefore, we have assumed that these resources are included in the current resource mix and will count toward RPS compliance for 2015, even though they are not specifically identified in GridView. The sum of current renewable generation in Gridview (22.5 TWh/yr) and the additional 10.8 TWh/yr of biomass and small hydro is 33.3 TWh/yr of renewable generation. The SSG-WI data also included, after minor modifications by CAISO, an additional 26.1 TWh/year from renewable resources expected to come on line between today and 2015 in the absence of Sunrise. An additional 20.2 TWh/year is therefore required to meet the 26.5% RPS target assumed for 2015. Sunrise allows the development of 10.3 TWh of incremental Salton Sea/IID renewables, leaving a net requirement of 9.2 TWh/year. Note that the renewables added for the Sunrise case add up to 78.9 TWh, slightly less than the 79.6 TWh target. This minor discrepancy stems from differences in the way the cases were originally put together and could not be corrected in time for this filing. Although the total amount of renewable energy did not exactly equal the target, we made sure that the base case and each alternative case had the same quantity of renewable energy.

Q. What resources did you use to obtain the additional RPS-compliant energy?

A. We relied heavily on the Center for Resource Solutions (CRS) 2005 report for the CPUC titled *Achieving a 33% Renewable Energy Target*, which identified renewable resources that could be used to fill the statewide gap between the 20% and 33% RPS goals. The resources we used were those identified by CRS, located within or near California, and whenever possible, in locations that would not cause substantial amounts of congestion.

Q. Does the composition of renewables vary for each case?

A. Yes. Table 2.2 below shows the GWh and MW added by location and type to the Gridview model for the Sunrise and the Base Case. Both cases require 9.2 TWh of incremental resources from a combination of wind power at Tehachapi, Altamont, Solano, and Colusa, plus new Geysers geothermal and distributed in-state biomass. The Base Case requires 11 TWh (= 20.2 TWh – 9.2 TWh) of additional resources to replace the Salton Sea/IID renewables that are developed under the Sunrise case; these come from a combination of geothermal in Mono, Inyo, Lake, and Modoc counties and in western Nevada, and wind in northeastern California.

Table 2.2. Resources Added to Sunrise and Base Cases.

Resource Type	County (Location)	MW Added: Sunrise Case	GWh Added: Sunrise Case		MW Added: Base Case	GWh Added: Base Case
Wind	Kern (Tehachapi)	560	1,717		560	1,717
Wind	Alameda (Altamont)	298	914		298	914
Wind	Solano	200	613		200	613
Geothermal	Sonoma (Geysers)	200	1,594		200	1,594
Wind	Colusa	300	920		300	920
Geothermal	Modoc/Siskiyou (Medicine Lake)	0	0		300	2,391
Wind	Lassen	0	0		300	920
Wind	Shasta	0	0		200	613
Geothermal	Mono/Inyo	0	0		350	2,790
Geothermal	Washoe NV	0	0		500	3,986
Geothermal	Lake (Sulfur Bank)	0	0		40	319
Biomass	CA - Distributed	422	3,401		422	3,401
Total Added		**1,980**	**9,159**		**3670**	**20,178**

Q. What is the additional renewable energy mix required in the South Bay case?

A. We assumed it is the same as the Base Case.

Q. What is the additional renewable energy mix required in the (Green Path + LEAPS) case?

A. We assumed it is the same as the Sunrise case.

Q. Is the renewable resource procurement scenario you describe above identical to the one used in your analysis of the cost of procuring renewables for RPS compliance?

A. No. The renewables procurement scenarios used to estimate the energy benefits were developed using the SSG-WI database as a starting point. The estimates of the RPS procurement costs described in Section 4 were developed using the CRS study as a starting point. Incompatibilities between the primary source data prevented us from reconciling the two approaches and developing scenarios that were entirely consistent.

Q. Are the Gridview results sensitive to either the locations or types of renewable resources added?

A. No, so long as the amount of renewable energy added is consistent from case to case, with sufficient transmission capability to accommodate the additional resources.

3. COST-EFFECTIVENESS RESULTS

Q. Please list the four cases that the CAISO has analyzed for this testimony.

A. The CAISO has used its TEAM methodology to repeat the analysis of the following four cases:

- Case 0: Revised Base Case described in Section 2.
- Case 1: Case 0 modified by Sunrise.
- Case 2: Case 0 modified by South Bay.
- Case 3: Case 0 modified by (Green Path + LEAPS).

Q. Please compare the energy costs and benefits from GridView for the Base Case, Sunrise, South Bay, and (Greenpath + LEAPS).

A. Tables 3.1 compares the energy related costs from each case and indicates that all of the alternatives provide small positive energy benefits compared to the CAISO's new Base Case.

- Sunrise energy benefit: $31 million per year in 2015
- South Bay energy benefit: $1 million per year in 2015
- Green Path + LEAPS energy benefit: $9 million per year in 2015

The reduction in energy benefits relative to the January 26, 2007 testimony is primarily due to the addition of significant renewable resources and associated transmission capacity in the Base Case. The renewable resources were added to meet the RPS, and resulted in lower LMPs and lower customer payments in the revised Base Case. This reduces the benefits of the alternatives. (Note that the new costs shown in Table 3.1 cannot be compared directly to the January 26th results because losses were double counted in the earlier runs). Finally, since the base case and each alternative now has the same amount of renewable generation, the estimated energy related benefits are now reflective of the other transmission or generation resources in the plan, rather than the amount of renewable generation.

Table 3.1: Annual Energy Costs and Benefits for 2015 ($ millions, nominal)

		A	*B*	*C*	*D*	*E*	*F*	*G*
	Summary of 2015 Cost and Benefits	**Costs**				**Benefits**		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	13,893	13,786	13,847	13,856	107	46	37
2	Less CAISO congestion cost (reduces TAC)	(109)	(77)	(90)	(97)	(32)	(19)	(12)
3	Less URG Margin (reduces URG bal acct)	(4,188)	(4,158)	(4,167)	(4,180)	(30)	(22)	(8)
4	Less IOU excess loss payments	(713)	(699)	(708)	(705)	(14)	(5)	(8)
5	**Subtotal Energy Cost and Benefit**	8,883	8,851	8,882	8,873	**31**	**1**	**9**

Q. How did you determine benefits for Cases 1-3 in 2015.

A. The benefits are defined as the cost difference between the Base Case and the alternative. The total net benefit is the sum of energy benefits from GridView modeling, reliability benefits from Section 2, and the difference in cost of procuring RPS-compliant renewable energy, less the cost of any transmission in the alternatives.

Q. How did you develop the RPS procurements costs?

A. The development of the RPS costs is detailed in Section 4. In general, the RPS procurement costs represent the total annual cost of purchasing renewable energy at a price that would provide a fair return to the generator, plus the annualized cost of any transmission that would be required to allow the renewable generators to sell power into the grid. The RPS procurement costs are from Table 4.1. For the Sunrise and (Green Path + LEAPS) cases the cost of the respective transmission projects are removed from the RPS procurement costs as needed to avoid counting the project costs twice. This is shown in Table 3.2.

Table 3.2: Adjusted RPS procurement costs ($millions per year)

		A	B	C	D	E	F	G	H
				Sunrise			Green Path + LEAPS		
		Base Case RPS Cost ($M)	**South Bay** RPS Cost ($M)	RPS Cost ($M)	Sunrise Transmission in RPS Costs	Adjusted RPS Cost ($M)	RPS Cost ($M)	(Green Path + LEAPS) Transmission in RPS Costs	Adjusted RPS Cost ($M)
1	2015	**4,125**	**4,125**	4,318	165	**4,153**	4,336	183	**4,153**
2	2020	**6,683**	**6,683**	6,678	165	**6,513**	6,696	183	**6,513**
3	Levelized	**5,320**	**5,320**	5,428	165	**5,264**	5,447	183	**5,264**

		A	B	C	D	E	F	G	H
				Sunrise			Green Path + LEAPS		
		Base Case RPS Cost ($M)	**South Bay** RPS Cost ($M)	RPS Cost ($M)	Sunrise Transmission in RPS Costs	Adjusted RPS Cost ($M)	RPS Cost ($M)	(Green Path + LEAPS) Transmission in RPS Costs	Adjusted RPS Cost ($M)
1	2015	**4,125**	**4,125**	4,318	165	**4,153**	4,336	183	**4,153**
2	2020	**6,685**	**6,685**	6,678	165	**6,513**	6,696	183	**6,513**
3	Levelized	**5,321**	**5,321**	5,428	165	**5,263**	5,447	183	**5,264**

Note that the transmission costs netted from the RPS costs are the values used in the RPS supply curve analysis. These values differ slightly from the numbers used in the rest of the cost effectiveness analysis, but the difference has no impact on the results.

Q. How does this approach compare to what the CAISO used for its January 26, 2007 testimony?

A. This approach refines the analysis used in the CAISO's January 26 testimony. In that testimony, the CAISO assumed that renewables purchased in the Base Case would have the same cost as renewables purchased in the Sunrise and (Green Path + LEAPS) cases. The analysis presented here explicitly models the renewable energy procurement costs for each case based on a WECC-wide renewable supply curve.

Q. What are the total benefits of each case 1-3 in 2015?

A. Table 3.3 shows that the total energy and reliability benefits for the Sunrise case in 2015 is $~~167~~ 169 million, which is greater than the Sunrise project cost of $157 million. The RPS procurement benefit, however, is negative $28 million, so the total net benefit of the Sunrise case ~~drops from positive $10~~ in 2015 ~~to~~ is negative $~~18~~ 15 million.

The South Bay case has low energy and reliability benefits of $~~43~~ 38 million, but the transmission costs are even lower at $9 million. The net benefit is $~~33~~ 28 million per year in 2015. The South Bay case has the same renewable mix as the Base Case so there is no RPS procurement benefit.

The (Green Path + LEAPS) case has $~~80~~ 72 million in energy and reliability benefits, offset by the negative $28 million of RPS procurement benefit and a $~~198~~ 205 million annual ~~transmission~~ cost. The resulting total net benefit is negative ~~118 118 million per year in 2015, and declines to negative~~ $~~146~~ 161 million per year in 2015 ~~when the negative RPS procurement benefit is added~~. Again, these results exclude any analysis of ancillary services benefits that might be provide by LEAPS or other alternatives.

Table 3.3: Costs and Benefits in 2015. Nominal millions of dollars per year.

		A	B	C	D	E	F	G
	Summary of 2015 Cost and Benefits	**Costs** ($ millions per year, nominal)				**Net Benefits** (Base case cost - Alt. case cost)		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	13,893	13,786	13,847	13,856	107	46	37
2	Less CAISO congestion cost (reduces TAC)	(109)	(77)	(90)	(97)	(32)	(19)	(12)
3	Less URG Margin (reduces URG bal acct)	(4,188)	(4,158)	(4,167)	(4,180)	(30)	(22)	(8)
4	Less IOU excess loss payments	(713)	(699)	(708)	(705)	(14)	(5)	(8)
5	**Subtotal Energy Cost and Benefit**	8,883	8,851	8,882	8,873	**31**	**1**	**9**
6	RMR Capacity Payments	80	31	114	80	49	(34)	-
7	RMR Operating Payments	60	42	60	60	18	-	-
8	CT Capacity Costs	53	-	-	6	53	53	47
9	Transmission cost for new CTs	19	-	-	2	19	19	16
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	211	72	174	148	**138**	**37**	**63**
13	**Total Energy and Reliability Benefits**					**169**	**38**	**72**
	RPS Procurement Cost							
14	Adjusted RPS Cost	4,125	4,153	4,125	4,153	(28)	-	(28)
15	**Total Benefits**					**142**	**38**	**44**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	9.3	205.2	(157.0)	(9.3)	(205.2)
17	**Total Costs and Benefits**	13,218	13,234	13,190	13,379	**(15)**	**28**	**(161)**

		A	B	C	D	E	F	G
	Summary of 2015 Cost and Benefits	**Costs** ($ millions per year, nominal)				**Net Benefits** (Base case cost - Alt. case cost)		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	13,893	13,786	13,847	13,856	107	46	37
2	Less CAISO congestion cost (reduces TAC)	(109)	(77)	(90)	(97)	(32)	(19)	(12)
3	Less URG Margin (reduces URG bal acct)	(4,188)	(4,158)	(4,167)	(4,180)	(30)	(22)	(8)
4	Less IOU excess loss payments	(713)	(699)	(708)	(705)	(14)	(5)	(8)
5	**Subtotal Energy Cost and Benefit**	8,883	8,851	8,882	8,873	**31**	**1**	**9**
6	RMR Capacity Payments	80	30	114	80	49	(34)	-
7	RMR Operating Payments	60	45	55	60	15	5	-
8	CT Capacity Costs	53	-	-	-	53	53	53
9	Transmission cost for new CTs	19	-	-	-	19	19	19
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	211	75	169	140	**136**	**42**	**71**
13	**Total Energy and Reliability Benefits**					**167**	**43**	**80**
	Transmission Cost							
14	**Levelized Cost of Transmission**	-	157	9.3	197.9	(157.0)	(9.3)	(197.9)
15	**Subtotal including Transmission Cost**	9,093	9,083	9,060	9,211	**10**	**33**	**(118)**
	RPS Procurement Cost							
16	Adjusted RPS Cost	4,125	4,153	4,125	4,153	(28)	-	(28)
17	**Total Costs and Benefits**	13,218	13,236	13,185	13,364	**(18)**	**33**	**(146)**

Q. What are the total benefits of each case 1-3 in 2020?

A. ~~The CAISO was not able to produce 2020 GridView analyses in time for inclusion in this testimony~~. ~~However, given the relatively small level of energy benefits, compared to reliability benefits, the CAISO does not see the energy benefits as being the major driver of the Sunrise project. Accordingly, at this time the CAISO has made the conservative assumption that benefits are constant in real dollars over the lifetime of the project.~~

~~Given that~~ Assuming that the energy benefits estimated for 2015, escalated by the rate of inflation, provide a reasonable estimate of annual energy benefits for 2020~~assumption~~, Table 3.4 shows that the total energy and reliability benefits for the Sunrise case is $~~190~~ 179 million, which is greater than the Sunrise project cost of $157 million. The RPS procurement benefit is $~~172~~ 170 million, so the total net benefit of the Sunrise case is $~~205~~ 191 million per year in 2020.

The South Bay case has low energy and reliability benefits of $~~46~~ 41 million, but the transmission costs are even lower at $9 million. The net benefit is $~~37~~ 32 million per year in ~~2015~~2020. The South Bay case has the same renewable mix as the Base Case so there is no RPS procurement benefit.

The (Green Path + LEAPS) case has $~~89~~ 80 million in energy and reliability benefits and $170 million in RPS procurement benefit, offset by $~~198~~ 205 million annual transmission cost. The total net benefit is ~~negative $109 million per year in 2020. The RPS procurement benefit is $172~~ a positive $~~63~~ 44 million per year in 2020.

Table 3.4: Costs and Benefits in 2020. Nominal millions of dollars per year.

		A	B	C	D	E	F	G
	Summary of 2020 Costs and Benefits	**Costs** ($ millions per year, nominal)				**Net Benefits** (Base case cost - Alt. case cost)		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,339	15,221	15,288	15,298	118	51	41
2	Less CAISO congestion cost (reduces TAC)	(120)	(85)	(99)	(107)	(35)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,624)	(4,591)	(4,600)	(4,615)	(33)	(24)	(9)
4	Less IOU excess loss payments	(788)	(772)	(782)	(779)	(15)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	9,807	9,773	9,806	9,797	**34**	**1**	**10**
6	RMR Capacity Payments	88	72	126	88	16	(38)	-
7	RMR Operating Payments	60	55	60	60	5	-	-
8	CT Capacity Costs	92	-	33	40	92	58	51
9	Transmission cost for new CTs	32	-	12	14	32	20	18
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	272	127	231	202	**144**	**41**	**70**
13	**Total Energy and Reliability Benefits**					**179**	**41**	**80**
	RPS Procurement Cost							
14	Adjusted RPS Cost	6,683	6,513	6,683	6,513	170	-	170
15	**Total Benefits**					**348**	**41**	**249**
	Transmission Cost							
16	**Levelized Cost of Transmission**	-	157	9.3	205.2	(157.0)	(9.3)	(205.2)
17	**Total Costs and Benefits**	16,762	16,570	16,729	16,718	**191**	**32**	**44**

		A	B	C	D	E	F	G
	Summary of 2020 Costs and Benefits	**Costs** ($ millions per year, nominal)				**Net Benefits** (Base case cost - Alt. case cost)		
		Base Case	Sunrise	South Bay	Green Path + LEAPS	Sunrise	South Bay	Green Path + LEAPS
	Energy and Reliability Costs							
1	Customer Payments from Gridview	15,339	15,221	15,288	15,298	118	51	41
2	Less CAISO congestion cost (reduces TAC)	(120)	(85)	(99)	(107)	(35)	(21)	(13)
3	Less URG Margin (reduces URG bal acct)	(4,624)	(4,591)	(4,600)	(4,615)	(33)	(24)	(9)
4	Less IOU excess loss payments	(788)	(772)	(782)	(779)	(15)	(6)	(9)
5	**Subtotal Energy Cost and Benefit**	9,807	9,773	9,806	9,797	**34**	**1**	**10**
~~6~~	~~RMR Capacity Payments~~	~~88~~	~~70~~	~~126~~	~~88~~	~~17~~	~~(38)~~	~~-~~
7	RMR Operating Payments	60	45	55	60	15	5	-
8	CT Capacity Costs	92	-	33	33	92	58	58
9	Transmission cost for new CTs	32	-	12	12	32	20	20
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	272	115	226	193	**156**	**46**	**79**
13	**Total Energy and Reliability Benefits**					**190**	**46**	**89**
	Transmission Cost							
14	**Levelized Cost of Transmission**	-	157	9.3	197.9	(157.0)	(9.3)	(197.9)
15	**Subtotal including Transmission Cost**	10,079	10,045	10,041	10,188	**33**	**37**	**(109)**
	RPS Procurement Cost							
16	Adjusted RPS Cost	6,685	6,513	6,685	6,513	172	-	172
17	**Total Costs and Benefits**	16,764	16,558	16,726	16,701	**205**	**37**	**63**

Q. What are the levelized benefits of each case 1-3?

A. Table 3. 5 shows our estimate of levelized costs and benefits for each case. The estimate is for the period 2010 through 2049, and includes the assumptions that energy costs and benefits remain constant in real dollars, and that RPS unit procurement costs remain constant in nominal dollars after 2020.

The most significant benefit from Sunrise is the estimated $~~146~~ 149 million in annual savings due to reduced RMR and avoided new CT cost savings. The line would also reduce energy costs by a modest $35 million per year and reduce the costs of procuring renewable resources by $~~58~~ 56 million per year. The total estimated annual benefit~~s~~ is $~~239~~ 241 million, which is $~~82~~ 84 million more than the estimated $157 million levelized annual cost of the Sunrise project.

The South Bay case has low energy and reliability benefits of $~~41~~ 38 million. The net benefit is $~~32~~ 29 million per year. The South Bay case has the same renewable mix as the Base Case so there is no RPS procurement benefit.

The (Green Path + LEAPS) case has $~~83~~ 84 million in energy and reliability benefits and $55 million in RPS procurement benefit. Subtracting the transmission project costs, the total net benefit ~~becomes negative $115 million per year. The levelized RPS procurement benefit is $57 million, so the total net benefit remains~~is negative ~~at~~ -$~~58~~ 66 million per year.

Table 3.5: Total project costs and benefits in million dollars per year, levelized

	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	60	125	85	30	(35)	6
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	149	261	225	**149**	**37**	**73**
13	**Total Energy and Reliability Benefits**					**185**	**38**	**84**
	RPS Procurement Cost							
14	Adjusted RPS Cost	5,320	5,264	5,320	5,264	**56**	**-**	**55**
15	**Total Benefits**					**241**	**38**	**139**
	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	15,604	15,660	15,754	**84**	**29**	**(66)**

	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	86	56	120	83	30	(34)	4
7	RMR Operating Payments - Levelized	58	44	54	58	15	5	-
8	CT Capacity Costs - Levelized	98	23	47	47	75	51	51
9	Transmission cost for new CTs-Levelized	34	8	16	16	26	18	18
10	Remediation cost to provide reactive support	-	-	-	-	-	-	-
11	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	276	131	236	204	**146**	**40**	**73**
13	**Total Energy and Reliability Benefits**					**181**	**41**	**83**
	Transmission Cost							
14	**Levelized Cost of Transmission**	-	157	9.3	197.9	**(157.0)**	**(9.3)**	**(197.9)**
15	**Total Including Transmission Cost**	10,346	10,322	10,315	10,461	**24**	**32**	**(115)**
	RPS Procurement Cost							
16	Adjusted RPS Cost	5,321	5,263	5,321	5,264	**58**	**-**	**57**
17	**Total Costs and Benefits**	15,667	15,585	15,636	15,725	**82**	**32**	**(58)**

Q. Have you updated your transmission costs since your January 26, 2007 testimony?

A. Yes, ~~we have adopted~~based on information provided by SDG&E~~'s,~~ ~~corrected levelized value of~~we are using a levelized cost of $157 million per year for the Sunrise project. This is $6 million lower than the levelized value we used in the January 26th testimony.

In following up on the discussions at the March 27th workshop, the CAISO has also updated the (Green Path + LEAPS) case's project cost estimates and has allocated only a portion of the Green Path's project cost to CAISO ratepayers, based on an estimated share of the Green Path's capacity used by these ratepayers. Table 3.6 below sets forth the refined cost estimates developed by the CAISO.

Table 3.6: (Green Path + LEAPS) Cost Estimate

		A		B		C	
		March 1 Filing		**April 20 Errata**			
		Total Cost		Total Cost		Allocated Cost	
1	Green Path	350	(2006$)	400	(2006$)	226.8	B1 * 56.7%
2	LEAPS			1283	(2005$)	1283	
3	Pumped Storage	650	(2006$)				
4	Transmission	350	(2006$)				
5	Network upgrades	0		TBD		TBD	
6	Total (Green Path + LEAPS) /1/	1,350	(2006$)	1,683	(mixed$)	1,510	(mixed$)
7	Escalation to 2010 $	111	(2%/yr)	167	(2%/yr)	152	(2%/yr)
8	**Total (2010$)**	**1,461**	L6 + L7	**1,850**	L6 + L7	**1,662**	L6 + L7
9	Adjust to Revenue Requirement	2,323	1.59 factor	2,680	1.45 factor	2,408	1.45 factor
10	Levelization Factor (8.18%, 41 yrs)	9%		9%		9%	
11	**Levelized Cost ($M/yr)**	**198**	L9 * L10	**228**	L9 * L10	**205.2**	L9 * L10

Notes

A6: March 1 LEAPS Cost: FERC-projected cost based on Staff Alternative (for modified pump storage project configuration) in the Final EIS for the LEAPS project: $ 1.327 billion (2005 dollars) from pg. 4-8. Adjusting for 2% inflation, this converts to $1353M in $2006 dollars (rounded to $1350M)

B1: April 20 GPN Cost: 1/4/07 note from LADWP

B2: April 20 LEAPS: Final EIS FERC report no-0191F-Jan 07

B5: The full costs of network upgrades cannot publicly be released at this time. The CAISO will update the total transmission costs once the information becomes available.

A9: Revenue requirement factor inferred from CSRTP report

B9 and C9: Revenue requirement factor inferred from SDG&E January 2007 testimony and exhibits for Sunrise costs
G1: 56.7% is the CAISO's estimate of the percentage of the GPN capacity that would be available for transportation of renewables for parties other than LADWP, SCPPA, or IID.

The LEAPS costs were obtained from TNHC's FERC filing (Final Environmental Impact Statement for Hydropower License-January 2007). The Green Path costs were obtained from documents used in a public workshop sponsored by LADWP.

When considering the LEAPS' and Green Path North's project estimates in Table 4, the CAISO is mindful of the following caveats. First, the cost estimate does not contain the full costs of network upgrades because they cannot be publicly released at this time.

Second, while these numbers represent the CAISO's best effort to develop cost estimates in the time available, the CAISO notes that each project proponent estimated its transmission costs by its own methodology. Therefore, the costs may not be strictly comparable.

Third, the CAISO does not have the exact breakdowns of all cost estimates. Therefore, they may not be complete and inclusive. For instance, the cost of prior ownership of land, environmental mitigation costs, optional equipment costs, contingencies, interests, taxes etc. may not be included in every cost estimate.

Finally, the cost estimate that we have for LEAPS is not for an Advanced Pumped Storage. Rather, it is for a classical design, similar to the Helms pumped storage unit owned by PG&E. For the advanced variable speed capability of LEAPS, additional equipment, controls and construction would be needed. Although the CAISO has requested a cost estimate for the additional equipment, controls and construction from the manufacturer (Voith Siemens), the CAISO has not received a response yet. To provide a rough estimate, however, the CAISO has created the following cost estimate in Table 3.7 based on some oral input from Voith Siemens. If included, the additional equipment, controls and construction requirement would increase the (Green Path + LEAPS) costs by $138 million, or approximately $17 million per year, levelized.

Table 3.~~6~~7: Additional estimated cost for making LEAPS an advanced unit

Advanced Pumped Storage Feature	Cost Estimate:
1. Additional Generator/ Turbine	$51.2 million
2. New Power electronics, cooling systems, controls	$20 million
3. Additional construction	$20 million
4. Additional electrical equipment	$15 million
5. Contingency for new technology- 30%	$32 million
Total Additional Cost:	$138 million

Aside from the updated project cost estimates for Green Path + LEAPS, Table 3.6 also shows an allocation factor of 56.7% applied to the Green Path project cost. This factor reflects the CAISO's belief, stated in its prior testimony and workshops, that use of Green Path facilities would not be free to its customers. The 56.7% is the CAISO's estimated share of the Green Path North project cost to be paid by CAISO ratepayers, via wheeling charges for renewable resource procurement. This estimate reflects the share of renewable energy that might be delivered to CAISO ratepayers through this line. The derivation of the

56.7% estimate is shown in Table 3.8 below. Our analysis assumes that Green Path induces 1900 additional MW of renewable resources to be developed in the IID area. The combination of SCPPA, IID and LADWP's use of this line for renewable and non-renewable resources, was 43.3 percent of 1900MWs, using the sources described below, leaving 56.7 percent to be used and paid for by the CAISO's ratepayers.

Table 3.8: Estimated Share of Green Path Paid by CAISO Customers

Line	Item	Amount	Comment
1	Total Capability (MW)	1900	2500MW potential less 600MW in the base case
2	*Less SCPPA and IID Share of project (MW)*	-304	16% according to LADWP's May 16, 2006 presentation on the Green path project
3	*Less LADWP's use of the line for renewables (MW)*	-150	Draft LADWP 2006 Integrated Resource Plan, Table D-1, May 06 (new geothermal forecast for RPS)
4	*Less LADWP's use of the line for Palo Verde generation (MW)*	-368	Draft LADWP 2006 Integrated Resource Plan, May 06 p. H-5
5	Net available to wheel renewables	1078	(L1-L2-L3-L4)
6	Percentage of Total	56.7%	(L4/L1)

4. COST TO MEET RENEWABLES PORTFOLIO STANDARD (RPS)

4.1 Overview

Q. What is the purpose of this section?

A. The purpose of this section is to explain the calculation of the cost of meeting California's RPS in 2015 and 2020 under each of the four cases described above in Section 1.

Q. How do the procurement cost estimates described in this section fit into the overall estimate of the costs and benefits of the cases?

A. As indicated in Section 3, the total net benefit of an alternative includes the change in the total procurement cost of RPS-compliant renewable energy. The procurement cost estimates in this section are used to compute that cost change.

Q. How did you estimate the renewable energy procurement cost under RPS for each case?

A. We estimated the cost using the following steps:

- Calculate the statewide RPS requirement for 2015 and 2020;
- Identify RPS-eligible generation resources potentially available to the state in those years;
- Estimate the average cost of groups of RPS-eligible resources in each of 17 geographic areas, including transmission upgrades necessary to integrate the resource into the high-voltage backbone grid; and

- Develop a least-cost portfolio of RPS resource clusters for each of the four cases in 2015 and 2020.

Q. What is the result of your analysis?

A. Table 4.1 shows the total cost of procuring RPS-compliant resources in 2015, including necessary transmission upgrades: Case 0, Base Case: $4.125 billion; Case 1, Sunrise: $4.318 billion; Case 2, South Bay: $4.125 billion; and Case 3, Green Path + LEAPS: $4.336 billion. Note that the renewable energy projects chosen under Case 1 or Case 3 are not part of the least-cost portfolio for RPS compliance in 2015, and their selection leads to higher costs than under the Base Case.

For year 2020, the total renewable energy procurement costs are: Case 0, Base Case: ~~$6.685~~$6.683 billion; Case 1, Sunrise: $6.678 billion; Case 2, South Bay: ~~$6.685~~$6.683 billion; and Case 3, Green Path + LEAPS: $6.696 billion. Hence, the Sunrise-related renewable energy projects would be selected as part of the least- cost portfolio for RPS compliance in 2020.

Table 4.1. Annual cost of complying with California Renewables Portfolio Standard in 2015 and 2020 for the four cases ($ millions)

Cost of RPS Compliance by Case

	2015 (Nominal $)		2020 (Nominal $)		40 Year Levelized (2010 $)	
Scenario	Total Cost	Cost relative to Base Case	Total Cost	Cost relative to Base Case	Total Cost	Cost relative to Base Case
Case 0. Base Case	$ 4,125	$ -	$ 6,683	$ -	$ 5,320	$ -
Case 1. Sunrise	$ 4,318	$ 192	$ 6,678	$ (5)	$ 5,428	$ 108
Case 2. South Bay	$ 4,125	$ -	$ 6,683	$ -	$ 5,320	$ -
Case 3. Greenpath	$ 4,336	$ 211	$ 6,696	$ 13	$ 5,447	$ 127

Cost of RPS Compliance by Case

	2015 (Nominal $)		2020 (Nominal $)		40 Year Levelized (2010 $)	
Scenario	Total Cost	Cost relative to Base Case	Total Cost	Cost relative to Base Case	Total Cost	Cost relative to Base Case
Case 0. Base Case	$ 4,125	$ -	$ 6,685	$ -	$ 5,321	$ -
Case 1. Sunrise	$ 4,318	$ 192	$ 6,678	$ (6)	$ 5,428	$ 108
Case 2. South Bay	$ 4,125	$ -	$ 6,685	$ -	$ 5,321	$ -
Case 3. (Green Path + LEAPS)	$ 4,336	$ 211	$ 6,696	$ 12	$ 5,447	$ 127

~~Note: A small clerical error is identified and corrected in the Workpapers for this table. Correcting this error would lower 2020 Total cost for the Base Case and Case 2 from $6,685MM to $6,683MM, a change of 0.02%. This correction would also lower the 40 year Levelized costs for both the base case and Case 2 from $5,321MM to $5,320. Additionally, the 2020 Cost Relative to Base Case for Sunrise would change from $(6) to $(5) for Case 1: Sunrise, and the 2020 Cost Relative to Base Case for (Green Path + LEAPS) would change from $12 to $13.~~

The third set of numbers represents the levelized annual cost of procuring RPS-compliant resources between 2010 and 2050. The levelized average renewable energy procurement costs are: Case 0, Base Case: $5.~~321~~ 320 billion; Case 1, Sunrise: $5.428 billion, Case 2, South Bay: $5.~~321~~ 320 billion; and Case 3, (Green Path + LEAPS): $5.447 billion. Note that these figures include transmission costs. To avoid double counting, Table 3.2 shows the adjusted RPS procurement costs net of transmission costs.

Q. How did you develop the levelized average cost estimate?

We derived the annual cash flows required to calculate the levelized cost from our 2010, 2015 and 2020 point estimates as follows:

- For 2011-2014, we used a straight-line interpolation between the 2010 and 2015 nominal-dollar estimates.
- For 2016-2019, we used a straight-line interpolation between the 2015 and 2020 nominal-dollar estimates.
- For 2021-2049, we extrapolated California loads and RPS requirements at the 2015-2020 growth rate (1.09%). We assumed that the average $/MWh cost would remain constant in nominal dollars throughout this period. The product of the RPS requirement and the $/MWh cost is the annual RPS procurement cost.
- The resulting stream of cash flows is then levelized using a discount rate of 8.18%.

4.2 RPS targets

Q. What are the RPS targets?

A. Based on statutory requirements, the CPUC and the California Power Authority (CPA), the RPS targets are 20% in 2010 and 33% in 2020. We used a straight-line interpolation to find the 26.5% target for 2015.

Q. What is the total quantity of RPS-compliant energy required in 2015 and 2020?

A. We assumed that all load-serving-entity's (LSE's) load and 75% of all publicly-owned-utility's (POU's) load are RPS-compliant. Based on load growth forecasts from the CEC (CEC, 2005), the total quantity of RPS-compliant energy required is approximately 79.6 TWh in 2015 and 104.4 TWh in 2020.

Q. What is the incremental quantity of RPS-compliant energy required in 2015 and 2020?

A. We estimate that LSEs have acquired 30,319 GWh of RPS-compliant energy by 2007.[8] Thus, the quantity of RPS-compliant energy required is 49.3 TWh in 2015 and 74.1 TWh in 2020, as summarized in Table 4.2 below.

Table 4.2. Load Forecasts and RPS targets in GWh for 2010, 2015 and 2020

Load Forecast and RPS Targets (GWh)	**2010**	**2015**	**2020**
IOU Bundled and DA Load	217,931	231,704	244,986
75% of Other Load	65,743	68,617	71,503
IOU + 75% of Other Load	**283,674**	**300,321**	**316,488**
RPS Target %	*20.0%*	*26.5%*	*33.0%*
RPS Target GWh	**56,735**	**79,585**	**104,441**
Existing Renewables	*-30,319*	*-30,319*	*-30,319*
New Renewables Needed	**26,416**	**49,266**	**74,122**

4.3 Renewable resources available to meet RPS targets

Q. How did you estimate the quantity, type and cost of RPS-compliant resources available to California LSEs?

A. First, we gathered the best available information on renewable resource costs, quantities and locations. Second, we grouped those resources into geographic

[8] CEC, *Net System Power: A Small Share of California's Power Mix in 2005*, April 2006 (CEC-300-2006-009-F). This value is net of 597 GWh of self-generation, which are assumed to be behind the meter and not RPS-eligible.

zones for the purpose of estimating transmission upgrade costs. Third, we developed levelized, per-MWh generation and transmission cost estimates for each resource zone. Finally, we arranged the results in a supply curve that shows an economic ranking of the available renewable resources relative to different levels of RPS requirements.

Q. Please describe the principal sources of data that underlie the renewable resource analysis.

A. We used two principal sources of information on resource cost and availability. For in-state resources, we relied on a 2005 report done for the CEC by the Center for Resource Solutions ("CRS Report"). The CRS Report is the latest and most comprehensive state-sponsored assessment of the resources required in the long-term to meet RPS requirements. For out-of-state resources, we relied principally on the Northwest Transmission Assessment Committee report on Canada-NW-California transmission costs ("NTAC Study"). The NTAC Study contains cost data not only for renewable resources, but critically for the purpose of this analysis, cost estimates for constructing the transmission upgrades necessary for bringing remote renewable resources to California. Table 4.3 shows the cost and available quantity of each resource type used in the analysis, along with the location. The table also shows the resource zone to which each individual resource was assigned.

Table 4.3. RPS-compliant resources by type and location

Resources Available for 33% RPS

Location	Resource Zone	Resource Type	MW	GWh	Gen LCOE $/MWh	Capacity Factor
Siskiyou	Northeast CA	Wind	200	613	$ 66	35%
Lassen	Northeast CA	Wind	300	920	$ 66	35%
Shasta	Northeast CA	Wind	200	613	$ 66	35%
Medicine Lake	Northeast CA	Geothermal	300	2,391	$ 86	91%
Sulfur Bank	Sonoma/Lake/Colusa	Geothermal	40	319	$ 86	91%
Colusa/Lake	Sonoma/Lake/Colusa	Wind	300	920	$ 66	35%
North Geysers	Sonoma/Lake/Colusa	Geothermal	400	3,189	$ 86	91%
Solano	Alameda/Solano	Wind	300	920	$ 66	35%
Altamont Repowering	Alameda/Solano	Wind	326	1,000	$ 66	35%
Altamont Expansion	Alameda/Solano	Wind	130	399	$ 66	35%
Tehachapi Phase 1	Tehachapi	Wind	700	2,146	$ 66	35%
Tehachapi Phase 2	Tehachapi	Wind	900	2,759	$ 66	35%
Tehachapi Phase 3	Tehachapi	Wind	1,700	5,212	$ 66	35%
Tehachapi Phase 4	Tehachapi	Wind	1,200	3,679	$ 66	35%
San Bernardino	San Bernardino/Mono	Wind	280	858	$ 66	35%
Mojave	San Bernardino/Mono	Solar Thermal	4,000	8,410	$ 120	24%
Mono	San Bernardino/Mono	Geothermal	300	2,391	$ 86	91%
San Diego	San Diego	Wind	750	2,300	$ 66	35%
Salton Sea	Imperial	Geothermal	800	6,377	$ 86	91%
Brawley	Imperial	Geothermal	100	797	$ 86	91%
Heber	Imperial	Geothermal	100	797	$ 86	91%
IID/Salton	Imperial	Solar Thermal	900	1,892	$ 120	24%
Urban Muni Waste	CA - Distributed	Biomass	860	6,931	$ 88	92%
Dairy	CA - Distributed	Biomass (Biogas)	37	298	$ 58	92%
Waste Water Treatment	CA - Distributed	Biomass (Biogas)	58	467	$ 58	92%
Landfill Gas	CA - Distributed	Biomass (Biogas)	500	4,030	$ 58	92%
Forest Management	CA - Distributed	Biomass	320	2,579	$ 88	92%
Pyramid Lake NV	Reno Area	Wind	1,000	3,066	$ 66	35%
Dixie Corridor (NV)	Reno Area	Geothermal	600	4,783	$ 86	91%
Washoe NV	Reno Area	Geothermal	500	3,986	$ 86	91%
NE NV	NE NV	Wind	1,000	3,066	$ 66	35%
Southern Oregon	Southern Oregon	Wind	1,200	3,679	$ 71	35%
Stateline OR/WA	Columbia Valley	Wind	3,000	9,198	$ 71	35%
BC-CA Greenline	British Columbia	Mixed	2,000	6,833	$ 72	39%
Montana	Montana	Wind	3,000	9,198	$ 60	35%
New Mexico	New Mexico	Wind	1,000	3,066	$ 66	35%
S. Wyoming	Wyoming	Wind	6,000	18,396	$ 60	35%
Salton Sea	Imperial Path 42	Geothermal	600	4,783	$ 86	91%

Q. Did you make any adjustments to the cost or availability of renewable resource in the source data?

A. We did not make any changes to the cost estimates in the studies we used. However, we modified the CRS list of available resources within California in the following ways:

- We added 300 MW of geothermal potential from the Mono county area, which was identified in previous resource potential studies.[9]
- We removed distributed solar PV from this list because in this study, it is assumed that PV is on the customer side of the meter and does not contribute to RPS compliance.
- We scaled the solar thermal potential to a level that would better match the current estimates of the amount likely to be developed in California. This downward scaling is necessary because the CRS listed a very large potential amount at this resource, albeit at a higher generation cost than the other renewables, as shown in table 4.3. Because solar thermal generation is a relatively high cost resource, the scaling down of the quantity available does not significantly impact our results.

Q. Why did you group the resources into geographic zones?

A. We grouped the resources into geographic zones for two reasons. First, the Sunrise project allows the development and integration of a large quantity of renewable resources (over 1,000 MW). In order to develop an apples-to-apples

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[9] CEC, *Geothermal Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report*, June 2005 (CEC-500-2005-105-SD). This resource was also referenced in Appendix II-A of the CRS report.

comparison of the Sunrise project to alternative projects, the alternatives must allow the development and integration of a similar quantity of renewable resources. Second, it is logical to focus on high-concentration resource zones from the standpoint of transmission, because large quantities of new resources are required to justify costly transmission upgrades.

Q. What are the zones used in the analysis?

A. There are seventeen zones in our analysis, including nine zones in California and eight out of state. Table 4.4 describes the developable capacity in MW, annual energy production in GWh, weighted average capacity factor, and weighted average generation cost of the resources in each zone. It should be noted that Zone 8, “CA distributed,” refers to biomass resources that are distributed throughout the state in typically small increments (less than 50 MW), and are not strongly concentrated within a specific region.

Q. How did you estimate the average resource cost in each zone?

A. For each zone, we calculated the average cost across all resource types represented in that zone, weighted by the quantity of GWh produced by each resource type. Table 4.4 shows the weighted average generation cost and capacity factor, along with the quantity of RPS-compliant energy available, for each resource cluster.

Table 4.4. Quantity of energy available, weighted average generation cost, and weighted average capacity factor for each resource cluster

Resource Cluster Totals				
Resource Zone	Available MW	Available GWh	Weighted Avg Gen Cost $/MWh	Weighted Avg Cap Factor $/MWh
Northeast CA	1,000	4,538	$77	52%
Sonoma/Lake/Colusa	740	4,427	$82	68%
Alameda/Solano	756	2,318	$66	35%
Tehachapi	4,500	13,797	$66	35%
San Bernardino/Mono	4,580	11,660	$109	29%
San Diego	750	2,300	$66	35%
Imperial	1,900	9,864	$93	59%
CA - Distributed	1,775	14,305	$78	92%
Reno Area	2,100	11,835	$81	64%
NE NV	1,000	3,066	$66	35%
Southern Oregon	1,200	3,679	$71	35%
Columbia Valley	3,000	9,198	$71	35%
British Columbia	2,000	6,833	$72	39%
Montana	3,000	9,198	$60	35%
New Mexico	1,000	3,066	$66	35%
Wyoming	6,000	18,396	$60	35%
Imperial Path 42	600	4,783	$86	91%
Total	**35,901**	**133,262**	**$75**	**49%**

4.4 Transmission cost estimates for renewable resources

Q. How did you determine the transmission upgrade costs necessary to integrate resources in each zone?

A. Where possible, we relied on the transmission costs estimates provided in the CRS report. For out of state resources in Oregon, Washington, BC, and Montana, we used the NTAC Study. For Wyoming, we used the Frontier line study.

For out of state resources where there were no pre-existing transmission studies, we assumed the construction of new transmission facilities to transmit the generated power to major transmission substations in the vicinity of large load centers in either northern or southern California (depending on the location of the out-of-state resources). To estimate the cost of these facilities, we worked together with CAISO planning staff to apply industry-standard rules of thumb for such items as the cost of substations and the cost per 500 kV circuit-mile in rural and urban areas.

Q. Do these estimates represent the incremental cost of bringing energy from remote renewable resources to a coastal load pocket such as San Diego?

A. No, the transmission costs included in this analysis assume upgrades only to bring energy to major substations on the high-voltage, "backbone" transmission system. Additional upgrades would be necessary to bring the energy all the way to a coastal load pocket, likely at substantial cost. The major exception is Sunrise, which brings renewable energy from the resource zone to a load pocket in San Diego. (Green Path + LEAPS) also increases San Diego's ability to import renewable energy, but by a smaller amount (625 MW of increased import capability vs. 1000 MW for Sunrise).

Q. How did you calculate the per-MWh cost of incremental transmission for each resource zone?

A. We converted the transmission upgrade cost into an annual revenue requirement assuming a 1.59 factor for loading the capital costs to translate direct costs to transmission revenue requirement levels. We then divided the annual costs by the annual quantity of energy transmitted (annual generation less real power losses) and levelized over 41 years using a discount rate of 8.18%. For simplicity and to provide an unbiased comparison of different transmission options, we assumed that all transmission lines are placed into service in 2007, and the levelized average transmission costs are expressed in 2007 dollars. Table 4.5 shows the investment cost in total dollars and $/MWh for each of the resource zones.

Table 4.5. Transmission capacity requirements and cost estimates by resource zone

Transmission Costs

Resource Cluster	Capacity (MW)	Energy Transfers (GWh)	Transmission Capital Costs ($MM)	Levelized Transmission Costs ($/MWh)
Northeast CA	1,000	4,538	$152	$4.53
Sonoma/Lake/Colusa	740	4,427	$27	$0.83
Alameda/Solano	756	2,318	$238	$13.88
Tehachapi	4,500	13,797	$2,313	$22.71
San Bernardino/Mono	4,580	11,660	$2,962	$34.41
San Diego	750	2,300	$182	$10.74
Imperial - Sunrise	1,900	9,864	$1,216	$16.71
Imperial - Greenpath	1,900	9,864	$1,350	$18.54
CA - Distributed	1,775	14,305	$113	$1.07
Reno Area	2,100	11,835	$1,000	$11.44
NE NV	1,000	3,066	$1,055	$46.61
Southern Oregon	1,200	3,679	$684	$25.19
Columbia Valley	3,000	9,198	$2,280	$33.58
British Columbia	2,000	6,833	$2,000	$39.65
Montana	3,000	9,198	$2,414	$35.55
New Mexico	1,000	3,066	$1,698	$75.02
Wyoming	6,000	18,396	$6,732	$49.57
Imperial Path 42	600	4,783	$44	$1.25

Transmission Costs

Resource Cluster	Capacity (MW)	Energy Transfers (GWh)	Transmission Capital Costs ($MM)	Levelized Transmission Costs ($/MWh)
Northeast CA	1,000	4,538	$152	$4.53
Sonoma/Lake/Colusa	740	4,427	$27	$0.83
Alameda/Solano	756	2,318	$238	$13.88
Tehachapi	4,500	13,797	$2,313	$22.71
San Bernardino/Mono	4,580	11,660	$2,962	$34.41
San Diego	750	2,300	$182	$10.74
~~Imperial - Sunrise~~	~~1,900~~	~~9,864~~	~~$1,216~~	~~$16.71~~
Imperial - (Green Path + LEAPS)	1,900	9,864	$1,350	$18.54
CA - Distributed	1,775	14,305	$113	$1.07
Reno Area	2,100	11,835	$1,000	$11.44
NE NV	1,000	3,066	$1,055	$46.61
Southern Oregon	1,200	3,679	$684	$25.19
Columbia Valley	3,000	9,198	$2,280	$33.58
British Columbia	2,000	6,833	$2,000	$39.65
Montana	3,000	9,198	$2,414	$35.55
New Mexico	1,000	3,066	$1,698	$75.02
Wyoming	6,000	18,396	$6,732	$49.74
Imperial Path 42	600	4,783	$44	$1.25

~~Note: A small clerical error is identified in the Workpapers for Table 4.1. Correcting this error would lower Levelized Transmission Costs for Wyoming from $49.74 to $49.57.~~

Q. Do the transmission cost estimates include any gathering or collecting facilities needed at the resource site?

A. No, we only included backbone transmission costs that were comparable to the (Green Path + LEAPS) and Sunrise case that also exclude gathering or collecting facilities. Although gathering and collecting facilities costs can be large and have a significant impact on our results, we expect that the inclusion of these costs would only improve the attractiveness of the Salton Sea geothermal resources, which have relatively high energy densities per acre compared to other renewable resource types.

Q. Do you assume that the costs of the new transmission facilities are shared with any non-RPS resources?

A. No, we assumed that the transmission costs are paid for only by the RPS-compliant resources in each resource zone. That is, the transmission costs are based on the sum of the nameplate capacity of the resources, and the energy transfers are calculated using the weighted average capacity factor in each zone.

Q. Do you include any real power losses or ancillary service costs in your transmission cost estimates?

A. No, we did not include any losses or ancillary services costs.

Q. Do you have any reason to believe that the simplifying assumptions used in your analysis are biased in favor of a particular resource type or location?

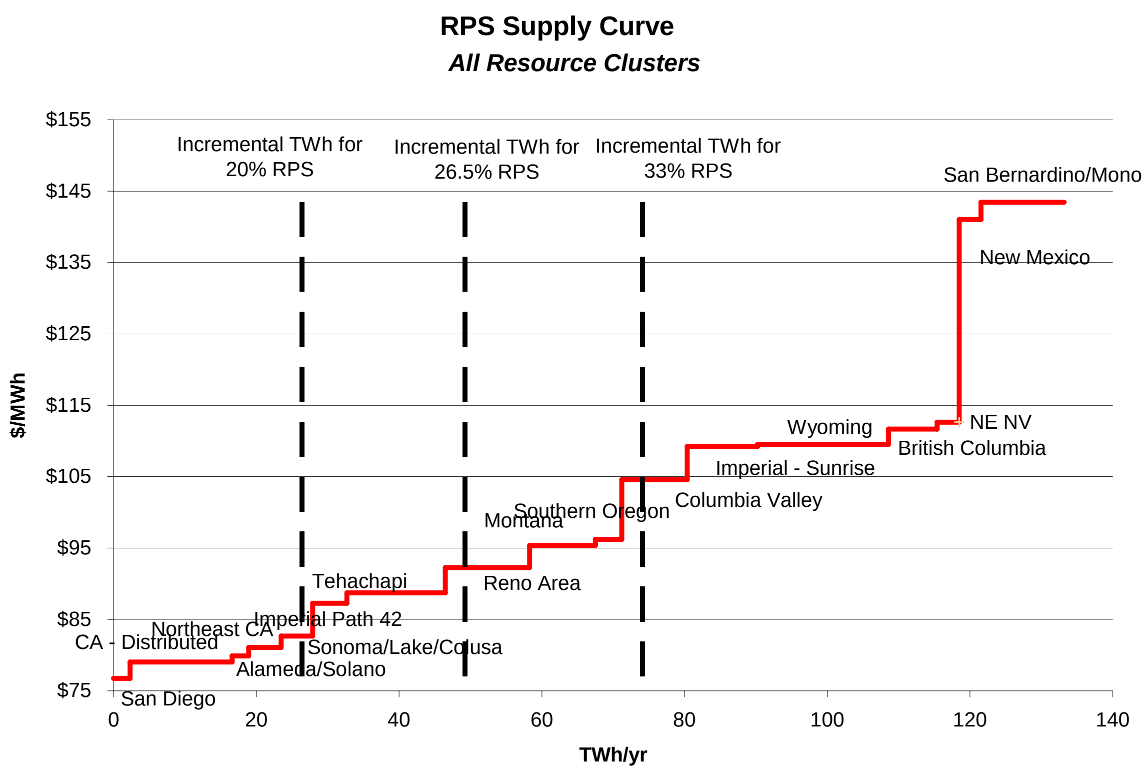
A. No. The assumption that transmission costs are based on nameplate generating capacity while energy transfers are calculated using average capacity factors results in somewhat higher costs for low-capacity-factor resources such as wind relative to alternative assumptions. However, this is largely, if not entirely, offset by omitting the cost of gathering and collecting facilities. Moreover, the real power losses associated with a remote resource such as Montana wind would undoubtedly be significantly higher than for a resource such as Imperial Valley geothermal. Lastly and perhaps most importantly, the uncertainty about the ultimate cost of any of the resources and transmission upgrades included in this analysis is very large. The resulting transmission costs displayed in Table 4.5 do not appear to be biased for or against any one resource type or location; however, it must be noted that the cost estimates that underlie the transmission alternatives is highly variable in quality and scope. The cost estimates for the Sunrise project, in particular, are based on detailed engineering studies rather than simple rules-of-thumb.

4.5 Renewable resource supply curves

Q. Please describe the supply curve that results from the resource and transmission costs.

A. Figure 4.1 shows the supply curve of renewable resource clusters available to California LSEs for compliance with RPS targets, along with the 2015 and 2020 targets. The resource clusters are arranged from lowest-cost to highest-cost, and the width of the horizontal bars reflects that quantity of renewable resources available in each group. The dashed vertical lines represent the 2010, 2015 and 2020 RPS targets. If the resource clusters were selected strictly on the basis of cost, all of the clusters up to Imperial Path 42 would be selected for 2010, all of the clusters up to Montana would be selected for 2015, and all of the clusters up to Columbia Valley would be selected for 2020. Neither Imperial - Sunrise nor Imperial - (Green Path + LEAPS) would be selected in any of the years.

Figure 4.1: Supply curve of potential resources for meeting California's RPS



Q. Are there any risks associated with the resource clusters that might prevent them from being developed at the estimated costs?

A. Yes, many of the cost estimates that we relied on for this analysis are highly speculative, and there are a host of risks that will inevitably prevent some of the resource clusters from being developed at our estimated costs. These include: (a) the risk that the actual cost to develop the resources is much higher than our estimates; (b) the risk that the actual cost of the transmission upgrades is much higher than our estimates; (c) the fact that utilities in other western states are also seeking renewable resources to comply with their own RPS targets, likely reducing the quantity of resources available to California LSEs; and (d) the risk that environmental or cultural concerns, difficulty assembling right-of-way, or other factors will prevent potentially economic projects from being developed in time to help California LSEs meet the 2015 and 2020 RPS targets.

Q. How did you modify the renewables supply curve in light of the development risks associated with speculative energy and transmission cost estimates?

A. In order to reflect the risks listed above, we made a simple modification to the renewables supply curve: we reduced the quantity of renewable resources available from all out-of-state resource zones by 50%. This reduction reflects the fact that it is highly unlikely that all of the projects will be constructed at our estimated costs, and some of them will likely not be constructed at all. We have no way of knowing which projects will go forward and which will not; therefore, rather than picking projects arbitrarily, we simply scaled down the expected availability of the out-of-state projects for the purpose of this ranking. This scenario was used to develop the costs of RPS compliance by case shown in Table 4.1 and the Adjusted RPS Procurement Costs shown in Table 3.2.

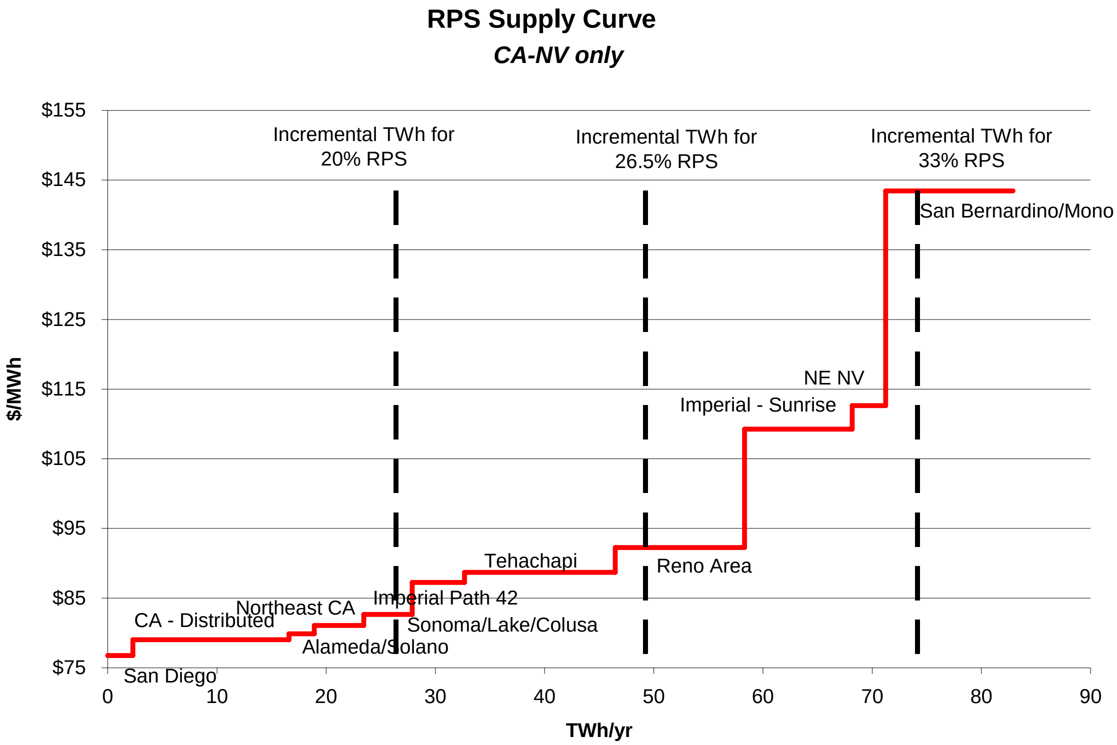
Q. Does this modification have a substantial impact on the estimated cost of RPS compliance?

A. No. The modification only raises the cost of compliance by 2.9%.

Q. **What is an alternative way of modifying the supply curves to reflect development risks?**

A. An alternative method would be to assume that all remote resources (e.g., those in the Pacific Northwest) are consumed in the areas where the resources are located or are otherwise unavailable to California LSEs for RPS compliance. Figure 4.2 shows a modified supply curve that includes only resources located in California and Nevada.

Figure 4.2. Supply curve of potential resources for meeting California's RPS using CA and NV resources only



Q. **Does the Sunrise project suffer from the risks described above?**

A. The Sunrise project is much farther along in the development cycle than most of the other projects considered in this analysis. SDG&E has already secured the right-of way and has presented a detailed engineering analysis in support of its cost estimates. Therefore, the Sunrise project is considerably less risky than the speculative projects that it is compared to in this analysis.

Q. **Has renewable resource development in California to-date followed a strict, least-cost ranking?**

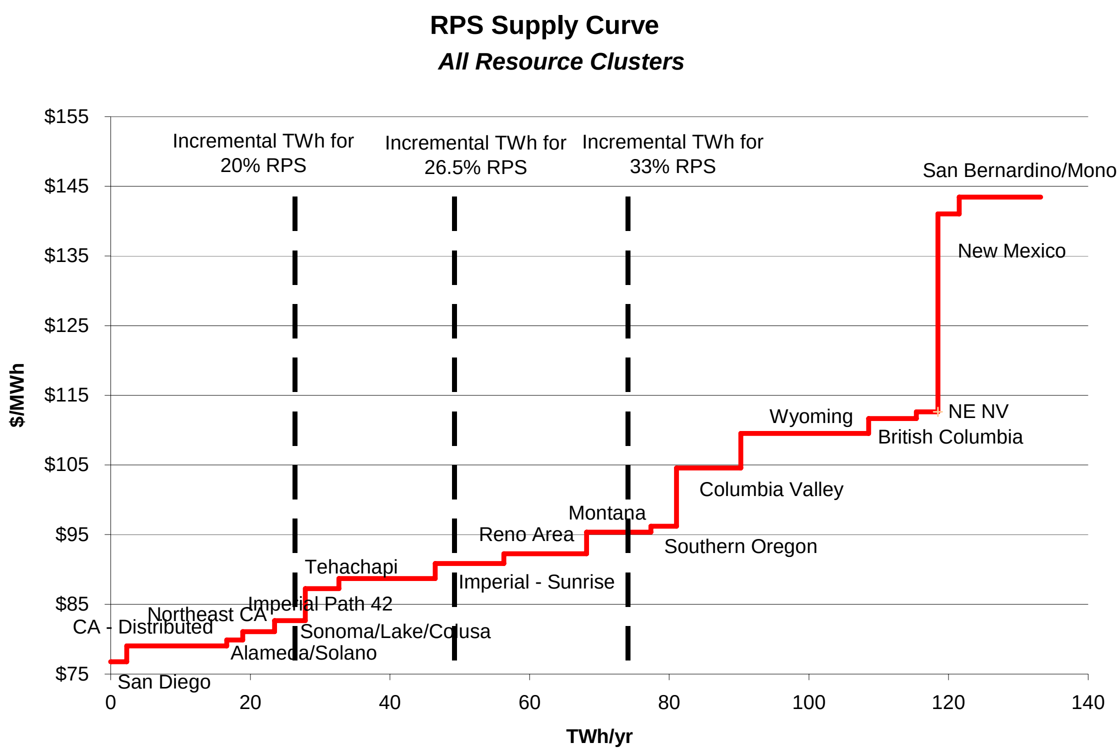
A. No. The renewable resources that have been developed or are under development by California LSEs in order to comply with the 2010 target are not always the least cost projects shown in Figure 4.1, as permitted by current state policy. For instance, projects are currently under development for wind in Tehachapi and solar thermal generation in San Bernardino, even though other lower cost resources from the figure do not currently have significant development plans underway. Thus, according these cost estimates, the resources under development for 2010 have not been developed strictly in order of lower- to higher-cost.

Q. **Does the supply curve analysis account for the fact that the Sunrise project brings renewable resources all the way to a coastal load pocket?**

A. No, for the alternative projects, the supply curve analysis reflects only the cost of developing and transmitting renewable resources to the backbone, high-voltage grid. The Sunrise project (and to a lesser extent the (Green Path + LEAPS) project) differs from other transmission projects in that it delivers renewable resources all the way to a coastal load pocket, thus providing additional reliability and energy benefits described in Section 3. This means that the supply curves depicted in this section are potentially misleading, when viewed on their own, because they do not represent an “apples-to-apples” comparison.

Figure 4.3 presents a modified supply curve in which Sunrise's total levelized energy and reliability benefits of $181 million/year are subtracted from the Sunrise case to derive a net cost of procuring renewables to the San Diego area from the Sunrise project. While this supply curve is not used to develop the RPS compliance cost estimates, it presents a more accurate picture of the relative net costs of the different resource clusters after accounting for differences in the transmission delivery point. It shows that renewable energy from the Salton Sea/IID area would be selected as part of the least-cost choice to meet not only the 33% RPS target, but also the interpolated 26.5% target.

Figure 4.3. Supply curve of potential resources for meeting California's RPS after accounting for differences in transmission delivery point



Q. **Are there any other RPS-compliant renewable resources that could potentially be developed and used by a California LSE?**

A. Yes, there is an almost unlimited quantity of theoretically-developable renewable resources that would be RPS-compliant, including ocean wave energy off the coast of California, tidal energy in the Golden Gate, distributed wind and solar thermal resources, and others. However, we are not aware of any other resources in the WECC that would be available to California LSEs in large quantities at costs that are comparable to the resources selected for this analysis.

4.6 Renewable resource portfolio selected for each case

Q. Please describe the renewable resource portfolio selected for Case 0.

A. Table 4.6 shows the resource portfolio selected for the Base Case in 2015 and 2020. The renewable energy procurement cost is $4.125 billion in 2015 and $6.~~685~~ 683 billion in 2020.

Table 4.6. Incremental resource potential portfolios selected for least-cost RPS compliance in 2015 and 2020, Case 0 (No Sunrise, No (Green Path + LEAPS))

Cost of RPS Compliance - 0: Base Case

Resource Cluster	Available Annual Energy (TWh)	Levelized Total Cost $/MWh	Cumulative Available Energy (TWh)	Cost Included in 2010 RPS ($MM)	Cost Included in 2015 RPS ($MM)	Cost Included in 2020 RPS ($MM)
Imperial (N/A)	0.0	$ -	0.0			
San Diego	2.3	$ 77	2.3	$ 176	$ 176	$ 176
CA - Distributed	14.3	$ 79	16.6	$ 1,130	$ 1,130	$ 1,130
Alameda/Solano	2.3	$ 80	18.9	$ 185	$ 185	$ 185
Northeast CA	4.5	$ 81	23.5	$ 368	$ 368	$ 368
Sonoma/Lake/Colusa	4.4	$ 83	27.9	$ 244	$ 366	$ 366
Imperial Path 42	4.8	$ 87	32.7	$ -	$ 417	$ 417
Tehachapi	13.8	$ 89	46.5	$ -	$ 1,224	$ 1,224
Reno Area	5.9	$ 92	52.4	$ -	$ 258	$ 546
Montana	4.6	$ 95	57.0	$ -	$ -	$ 438
Southern Oregon	1.8	$ 96	58.8	$ -	$ -	$ 177
Columbia Valley	4.6	$ 105	63.4	$ -	$ -	$ 481
Wyoming	9.2	$ 109	72.6	$ -	$ -	$ 1,006
British Columbia	3.4	$ 112	76.0	$ -	$ -	$ 168
NE NV	1.5	$ 113	77.6	$ -	$ -	$ -
New Mexico	1.5	$ 141	79.1	$ -	$ -	$ -
San Bernardino/Mono	11.7	$ 143	90.8	$ -	$ -	$ -
Total				**$ 2,104**	**$ 4,125**	**$ 6,683**

Cost of RPS Compliance - 0: Base Case

Resource Cluster	Available Annual Energy (TWh)	Levelized Total Cost $/MWh	Cumulative Available Energy (TWh)	Cost Included in 2015 RPS ($MM)	Cost Included in 2020 RPS ($MM)
Imperial (N/A)	0.0	$ -	0.0		
San Diego	2.3	$ 77	2.3	$ 176	$ 176
CA - Distributed	14.3	$ 79	16.6	$ 1,130	$ 1,130
Alameda/Solano	2.3	$ 80	18.9	$ 185	$ 185
Northeast CA	4.5	$ 81	23.5	$ 368	$ 368
Sonoma/Lake/Colusa	4.4	$ 83	27.9	$ 366	$ 366
~~Imperial Path 42~~	~~4.8~~	~~$ 87~~	~~32.7~~	~~$ 417~~	~~$ 417~~
Tehachapi	13.8	$ 89	46.5	$ 1,224	$ 1,224
Reno Area	5.9	$ 92	52.4	$ 258	$ 546
Montana	4.6	$ 95	57.0	$ -	$ 438
Southern Oregon	1.8	$ 96	58.8	$ -	$ 177
Columbia Valley	4.6	$ 105	63.4	$ -	$ 481
Wyoming	9.2	$ 110	72.6	$ -	$ 1,004
British Columbia	3.4	$ 112	76.0	$ -	$ 171
NE NV	1.5	$ 113	77.5	$ -	$ -
New Mexico	1.5	$ 141	79.1	$ -	$ -
San Bernardino/Mono	11.7	$ 143	90.7	$ -	$ -
Total				**$ 4,125**	**$ 6,685**

~~Note: A small clerical error is identified in the Workpapers for Table 4.1. Correcting this error would lower Levelized Total Costs for Wyoming from $110 to $109 and would lower the Total Cost included in 2020 RPS from $6,685 to $6,683~~.

Q. Please describe the renewable resource portfolio selected for Case 1.

A. Table 4.7 shows the resource portfolio selected for the Case 1: Sunrise in 2015 and 2020. The renewable energy procurement cost is $192 million higher than the Base Case in 2015, but $~~6.3~~5 million lower than the Base Case in 2020.

Table 4.7. Incremental resource potential portfolios selected for least-cost RPS compliance in 2015 and 2020, Case 1 (Sunrise)

Cost of RPS Compliance - 1: Sunrise

Resource Cluster	Available Annual Energy (TWh)	Levelized Total Cost $/MWh	Cumulative Available Energy (TWh)	Cost Included in 2010 RPS ($MM)	Cost Included in 2015 RPS ($MM)	Cost Included in 2020 RPS ($MM)
Imperial - Sunrise	9.9	$ 109	9.9	$ 1,077	$ 1,077	$ 1,077
San Diego	2.3	$ 77	12.2	$ 176	$ 176	$ 176
CA - Distributed	14.3	$ 79	26.5	$ 1,126	$ 1,130	$ 1,130
Alameda/Solano	2.3	$ 80	28.8	$ -	$ 185	$ 185
Northeast CA	4.5	$ 81	33.3	$ -	$ 368	$ 368
Sonoma/Lake/Colusa	4.4	$ 83	37.8	$ -	$ 366	$ 366
Imperial Path 42	4.8	$ 87	42.5	$ -	$ 417	$ 417
Tehachapi	13.8	$ 89	56.3	$ -	$ 597	$ 1,224
Reno Area	5.9	$ 92	62.2	$ -	$ -	$ 546
Montana	4.6	$ 95	66.8	$ -	$ -	$ 438
Southern Oregon	1.8	$ 96	68.7	$ -	$ -	$ 177
Columbia Valley	4.6	$ 105	73.3	$ -	$ -	$ 481
Wyoming	9.2	$ 109	82.5	$ -	$ -	$ 91
British Columbia	3.4	$ 112	85.9	$ -	$ -	$ -
NE NV	1.5	$ 113	87.4	$ -	$ -	$ -
New Mexico	1.5	$ 141	89.0	$ -	$ -	$ -
San Bernardino/Mono	11.7	$ 143	100.6	$ -	$ -	$ -
Total				**$ 2,380**	**$ 4,318**	**$ 6,678**
Difference from 0: Base Case					**$ 192**	**$ (5)**

Cost of RPS Compliance - 1: Sunrise

Resource Cluster	Available Annual Energy (TWh)	Levelized Total Cost $/MWh	Cumulative Available Energy (TWh)	Cost Included in 2015 RPS ($MM)	Cost Included in 2020 RPS ($MM)
Imperial - Sunrise	9.9	$ 109	9.9	$ 1,077	$ 1,077
San Diego	2.3	$ 77	12.2	$ 176	$ 176
CA - Distributed	14.3	$ 79	26.5	$ 1,130	$ 1,130
Alameda/Solano	2.3	$ 80	28.8	$ 185	$ 185
Northeast CA	4.5	$ 81	33.3	$ 368	$ 368
Sonoma/Lake/Colusa	4.4	$ 83	37.8	$ 366	$ 366
~~Imperial Path 42~~	~~4.8~~	~~$ 87~~	~~42.5~~	~~$ 417~~	~~$ 417~~
Tehachapi	13.8	$ 89	56.3	$ 597	$ 1,224
Reno Area	5.9	$ 92	62.2	$ -	$ 546
Montana	4.6	$ 95	66.8	$ -	$ 438
Southern Oregon	1.8	$ 96	68.7	$ -	$ 177
Columbia Valley	4.6	$ 105	73.3	$ -	$ 481
Wyoming	9.2	$ 110	82.5	$ -	$ 92
British Columbia	3.4	$ 112	85.9	$ -	$ -
NE NV	1.5	$ 113	87.4	$ -	$ -
New Mexico	1.5	$ 141	88.9	$ -	$ -
San Bernardino/Mono	11.7	$ 143	100.6	$ -	$ -
Total				**$ 4,318**	**$ 6,678**
Difference from 0: Base Case				**$ 192**	**$ (6)**

~~Note: A small clerical error is identified in the Workpapers for Table 4.1. Correcting this error would lower Levelized Total Costs for Wyoming from $110 to $109 and would change the "Difference from 0: Base Case" for Cost Included in 2020 RPS from $(6) to $(5).~~

Q. Please describe the renewable resource portfolio selected for Case 2.

A. It is identical to the one for the Base Case.

Q. Please describe the renewable resource portfolio selected for Case 3: (Green Path + LEAPS).

A. Table 4.8 shows that the total renewable energy procurement cost are $211 million higher than the Base Case in 2015 and $~~11~~ 13 million higher than the Base Case in 2020.

Table 4.8. Incremental resource potential portfolios selected for least-cost RPS compliance in 2015 and 2020, Case 3 (Green Path + LEAPS)

Cost of RPS Compliance - 3: Greenpath

Resource Cluster	Available Annual Energy (TWh)	Levelized Total Cost $/MWh	Cumulative Available Energy (TWh)	Cost Included in 2010 RPS ($MM)	Cost Included in 2015 RPS ($MM)	Cost Included in 2020 RPS ($MM)
Imperial -Greenpath	9.9	$ 111	9.9	$ 1,095	$ 1,095	$ 1,095
San Diego	2.3	$ 77	12.2	$ 176	$ 176	$ 176
CA - Distributed	14.3	$ 79	26.5	$ 1,126	$ 1,130	$ 1,130
Alameda/Solano	2.3	$ 80	28.8	$ -	$ 185	$ 185
Northeast CA	4.5	$ 81	33.3	$ -	$ 368	$ 368
Sonoma/Lake/Colusa	4.4	$ 83	37.8	$ -	$ 366	$ 366
Imperial Path 42	4.8	$ 87	42.5	$ -	$ 417	$ 417
Tehachapi	13.8	$ 89	56.3	$ -	$ 597	$ 1,224
Reno Area	5.9	$ 92	62.2	$ -	$ -	$ 546
Montana	4.6	$ 95	66.8	$ -	$ -	$ 438
Southern Oregon	1.8	$ 96	68.7	$ -	$ -	$ 177
Columbia Valley	4.6	$ 105	73.3	$ -	$ -	$ 481
Wyoming	9.2	$ 109	82.5	$ -	$ -	$ 91
British Columbia	3.4	$ 112	85.9	$ -	$ -	$ -
NE NV	1.5	$ 113	87.4	$ -	$ -	$ -
New Mexico	1.5	$ 141	89.0	$ -	$ -	$ -
San Bernardino/Mono	11.7	$ 143	100.6	$ -	$ -	$ -
Total				**$ 2,398**	**$ 4,336**	**$ 6,696**
Difference from 0: Base Case					**$ 211**	**$ 13**

Cost of RPS Compliance - 3: (Green Path + LEAPS)

Resource Cluster	Available Annual Energy (TWh)	Levelized Total Cost $/MWh	Cumulative Available Energy (TWh)	Cost Included in 2015 RPS ($MM)	Cost Included in 2020 RPS ($MM)
Imperial - (Green Path + LEAPS)	9.9	$ 111	9.9	$ 1,095	$ 1,095
San Diego	2.3	$ 77	12.2	$ 176	$ 176
CA - Distributed	14.3	$ 79	26.5	$ 1,130	$ 1,130
Alameda/Solano	2.3	$ 80	28.8	$ 185	$ 185
Northeast CA	4.5	$ 81	33.3	$ 368	$ 368
Sonoma/Lake/Colusa	4.4	$ 83	37.8	$ 366	$ 366
~~Imperial Path 42~~	~~4.8~~	~~$ 87~~	~~42.5~~	~~$ 417~~	~~$ 417~~
Tehachapi	13.8	$ 89	56.3	$ 597	$ 1,224
Reno Area	5.9	$ 92	62.2	$ -	$ 546
Montana	4.6	$ 95	66.8	$ -	$ 438
Southern Oregon	1.8	$ 96	68.7	$ -	$ 177
Columbia Valley	4.6	$ 105	73.3	$ -	$ 481
Wyoming	9.2	$ 110	82.5	$ -	$ 92
British Columbia	3.4	$ 112	85.9	$ -	$ -
NE NV	1.5	$ 113	87.4	$ -	$ -
New Mexico	1.5	$ 141	88.9	$ -	$ -
San Bernardino/Mono	11.7	$ 143	100.6	$ -	$ -
Total				**$ 4,336**	**$ 6,696**
Difference from 0: Base Case				**$ 211**	**$ 12**

~~Note: A small clerical error is identified in the Workpapers for Table 4.1. Correcting this error would lower Levelized Total Costs for Wyoming from $110 to $109 and would change the "Difference from 0: Base Case" for Cost Included in 2020 RPS from $12 to $13.~~

5. RELIABILITY ANALYSIS

Q. Please summarize the results from the reliability analysis of the four cases listed in Section 3.

A. Table 5.1 summarizes the reliability results under the CAISO's G-1/N-1 criteria for 2015 Heavy Summer. These results lead to the following observations:

- For Case 0: updated Base Case, an additional 565 MW of CTs (or other local resources) would be necessary to serve load and maintain SDG&E's existing non-simultaneous import limit (NSIL) of 2500 MW.
- For Case 1: Sunrise, the 565 MW of CTs are not required because in-area resource needs would be met by imports. In addition, the Sunrise project would allow the elimination of approximately 435 MW of local capacity requirements in the San Diego load pocket in the year 2015.
- For Case 2: South Bay, the 565 MW of CTs are not required because in-area resource needs would be met. With South Bay Re-power, the largest G-1 will then be the 620 MW South Bay plant; the 561 MW Otay Mesa plant will be dispatched on-line.. However, all generation in the San Diego load pocket would be required to meet local capacity needs in the year 2015.
- For Case 3: (Green Path + LEAPS), ~~the 5~~65 MW of new CTs are ~~not~~ required ~~because in-area resource needs would be met by imports~~in 2015. ~~However,~~ ~~a~~All existing generation in the San Diego load pocket would also be required to meet local capacity needs in the year 2015.

Table 5.1: Reliability assessment results for 2015 Heavy Summer by case

UPDATED JANUARY 26, 2007 CAISO TESTIMONY CASE - SDG&E IMPORT ASSESSMENT

MARCH 1, 2007 SUPPLEMENTAL TESTIMONY FILING

	2015HS Sunrise Powerlink (All-Lines In Service)	**2015HS Sunrise Powerlink (N-1 Condition***)**	**2015HS South Bay Re-power (All Lines In Service) (CT's are added as necessary)**	**2015HS South Bay Re-power (N-1 Condition*) (CT's are added as necessary)**	**2015HS Green Path North + LEAPS (All-Lines In Service)**	**2015HS Green Path North + LEAPS (N-1 Condition*)**	**2015HS Reference Case + CT's (All Lines In Service) (CT's are added as necessary)**	**2015HS Reference Case + CT's (N-1 Condition*) (CT's are added as necessary)**
CONTINGENCY	**G-1: Otay Mesa**	**G-1:Otay Mesa N-1: IV-Miguel**	**G-1: South Bay**	**G-1:South Bay N-1: IV-Miguel**	**G-1: Otay Mesa**	**G-1:Otay Mesa N-1: IV-Miguel**	**G-1: Otay Mesa**	**G-1:Otay Mesa N-1: IV-Miguel**
SDG&E LOAD (MW)	5181	5181	5181	5181	5181	5181	5181	5181
SDG&E INTERNAL GENERATION (MW)	2271	2271	2832	2832	2271	2271	2271	2271
REQUIRED CT'S (MW)						65	157	565
SDG&E SYSTEM LOSSES (MW)	98	135	98	138	106	155~~215~~	97	155
TOTAL SDG&E IMPORT (MW)	**3009**	**3045**	**2448**	**2488**	**3016**	**3000~~3125~~**	**2850**	**2500**
Surplus (MW)	**991**	**455**	**402**	**12**			**0**	
Total Import Capability (MW)	4000	3500	2850	2500	N/A	**3000**~~N/A~~	2850	2500

NOTE:

This table presents a thermal analysis justification for the need of the subject import line.

This table is not intended as a rigorous import analysis or verification of any import limits.

* SPS for Cross Tripping of the Imperial Valley - La Rosita 230kV Line helps preventing internal 230kV CFE system from being overloaded.

** G-1 of Otay Mesa, System Re-adjustment in Base Cases. The contingency analysis includes an N-1 on the Imperial Valley - Miguel 500kV line (N-1).

*** No need for Cross Trip SPS (Post Sun Path Project Scenario).

Q. Did the CAISO also conduct additional power flow analyses for the Base Case and the alternative scenarios?

A. Yes, we did. As promised in the January 8, 2007 Motion for Extension, the CAISO has performed these same studies on the 2015 Heavy Summer case for all four scenarios. The results of these studies have identified similar reliability issues as those in the CSRTP report. In addition, the CAISO also revised the January 26, 2007, power flow cases to resolve the modeling issues that were the most pronounced during the simultaneous loss of two nuclear generating units. After extensive investigation it was found that the modeling of the Grizzly-Malin 500 kV line was incorrect. The modeling of this line has been corrected.

Q. What conclusions can be drawn from the preceding reliability study results?

A. ~~The following conclusions are based on the previous post-transient and transient-stability contingency simulations on the 2015 Heavy Summer case for all four scenarios. However, although the conclusions of the revised analysis are expected to be similar, they are subject to change once the revised analysis is complete.~~The conclusions are as follows:

- The Sunrise case analysis showed that SDG&E's local capacity requirements would be reduced by about 1000 MW, and that the Sunrise case has no transient stability concerns. However, there were a few minor new post-transient voltage deviation criteria violations identified, but for all of these violations the system performance was much improved compared to the reference case without Sunrise. The ~~only~~ reliability concerns with the Sunrise Project were:~~is~~

- The thermal overload on CFE's Herradura 230/115kV 225 MVA transformer under an N-1 contingency of San Felipe – Central 500kV line. This contingency overloading concern can be mitigated by installing an SPS to curtail some generation connecting to Imperial Valley Substation.
- The other overloading concern is on the Carlton Hills – Sycamore 138kV line under an N-1 contingency of Imperial Valley – Miguel 500kV line. However, SDG&E also identified the need to mitigate this line loading concern in its Annual Transmission Expansion Plan.

- For the South Bay Repowering case, there would be no import capability improvement. There are no transient ~~or post-transient~~ stability concerns and post-transient concerns are similar to the reference case in the SCE area but improved in the SDG&E area. A review of the facility loading results indicated that this alternative does not cause new facility overload.
- For the (Green Path North + LEAPS) case, SDG&E's import capability would increase by 500 MW. Our reliability analysis is based on the performance of the system during the 2015 summer peak hour. The analysis shows that with this project in place, and an import level at 3000 MW, or 500 MW above the base case, there are some small problems that the CAISO assumed to have been fixed with this project in place. However, further import increases would overload three large transmission lines (see discussion below on the San Diego import limit analysis). The transient stability and post-transient analysis identified the following reliability problems:

~~For the (Green Path North + LEAPS) case, SDG&E's import capability is also expected to increase. However, this alternative has potential transient frequency concerns in which the frequency at various CFE load buses dips below 59.6 Hz for more 6 cycles. In addition, there were several facility overloading concerns under various N-1 or N-2 contingencies. CFE's Herradura 230/115kV 225 MVA transformer overloaded under numerous contingency conditions. In addition, IID's Coachella-Midway 230kV lines overloaded following the contingency of the IV-Miguel 500 kV line. Post-transient analysis also identified multitudes post-transient voltage deviations that exceed WECC limits under various N-1 or N-2 contingencies. The voltage deviation performance under contingency conditions degraded significantly with the alternative relative to the reference case.~~

1. Transient frequency criteria violations. The frequency at various CFE load buses dips below 59.6 Hz for more than 6 cycles.
2. Facility overloading under contingencies. CFE's Herradura 230/115kV 225 MVA transformer overloads under numerous contingency conditions. In addition, IID's RTAP2 – RTP1 92kV line is overloaded under Imperial Valley – Miguel 500kV line contingency.
3. Post-transient voltage deviations. A post-transient analysis identified many post-transient voltage deviations that exceed WECC limits under various N-1 or N-2 contingencies. Relative to the CAISO's base case, the alternative significantly degrades the voltage deviation performance under contingency conditions.

Q. Please describe the San Diego import limit analysis for the (Green Path + LEAPS) alternative?

A. Two import power flow cases were prepared for the analysis: (a) a pre-project case with 2500 MW import into San Diego under the G-1/N-1 contingency condition (Otay Mesa/SWPL), and (b) a post-project case that includes the LEAPS Project and 3000 MW import into San Diego under the same G-1/N-1 scenario. For the post-project case (b), the CAISO modeled 500 MW of import using the LEAPS Project, and the remaining 2500 MW through Path 44 (South of SONGS). Power flow and post-transient analyses were performed to determine thermal loading impact and post-transient voltage deviation due to the additional 500 MW of import to San Diego. A summary of the study results is described below:

- The post-project case (b) would cause loading on the San Onofre – San Luis Rey 230kV # 1 line to be 99% of its emergency rating (1150 MVA) under the contingency of its parallel line.
- Higher imports would require adding a fourth San Onofre – San Luis Rey 230kV line (18 miles). Adding a new 230kV line in this corridor is challenging because new Rights-of-Way and a CPCN would be required in this populated and environmentally sensitive area.
- 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.

- The post-project case also triggered new overloading concerns for Escondido 230/69kV Bank # 3, Escondido – Felicita 69kV#1 line, Lilac – Rincon 69kV #1 line, San Luis Rey 230/69kV Banks # 1 and 2. These underlying facility loading concerns, however, can be mitigated by installing an additional transformer bank capacity at the substation, or by re-conductoring 69kV lines. These actions do not require the more complex CPCN filing as required for new 230kV or 500kV lines.

Q. What conclusions can be drawn from the results of the San Diego import limit analysis for the (Green Path + LEAPS) alternative ?

A. Based on the results above, the CAISO believes that without substantially increasing the costs of the LEAPS related transmission, the LEAPS project would only increase the import capability of SDG&E by 500 MW, provided that the mitigation for thermal loading concerns described above were addressed.

However, these results are considered preliminary and approximate, due to the abbreviated time frame available for this analysis. Given the approximate nature of this analysis, the CAISO will assume a one-to-one translation between increased import capability with the Imperial Valley-Miguel 500 kV line outage and the MW reduction in local capacity requirements, without any adjustment for losses. In other words, it will be assumed for this Sunrise Power Link alternative analysis that LEAPS would reduce the local capacity requirements in the San Diego area by 500 MW.

6. RECOMMENDATION

Q. What conclusions can be drawn at this point in the evaluation process?

A. We have three conclusions. First, we believe that the energy benefits for Sunrise to be modest but continue to be positive. We have completed a considerable number of GridView runs and consider this finding to be robust over a fairly wide range of plausible assumptions. Second, and in contrast to the energy benefits, the reliability cost savings that are made possible because of Sunrise are fairly well understood and should offset a large portion of the project costs. Third and perhaps most importantly, Sunrise provides RPS benefits without which it will be difficult for California LSEs to comply with a 33% RPS by 2020. If the energy and reliability benefits are netted from the full costs of Sunrise, the project provides access to a large group of renewable resources with no incremental costs of transmission. The analyses and filings to date have not called into question the CAISO's initial recommendation of Sunrise for approval by the Commission.

Q. In light of the complexity of the Sunrise evaluation, what are your recommendations for going forward?

A. In April, once all of the parties' analyses have been completed, and the CAISO has completed its own analysis of both the 2010 and 2020 cases, we propose to file testimony that illustrates the ranking of each plan under a set of plausible scenarios that illustrate the importance of each of the key sources of uncertainty. In the meantime, we recommend that the Commission schedule another workshop so that the CAISO will have an opportunity to discuss the data and information developed for this testimony and answer questions from the parties to the proceeding.

Q. Does this conclude your Initial Testimony, Part II?

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 Testimony Of The California Independent System Operator Corporation, Part III, to each party in Docket No. A.06-08-010.

Executed on April 20, 2007 at Folsom, California.

/s/Susan L. Montana
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