BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

ERRATA TO THE

INITIAL TESTIMONY OF THE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

PART II (SERVED ON MARCH 1, 2007)

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Dated: March 23, 2007

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Subsequent to serving Part II of its Initial Testimony in this proceeding, the California Independent System Operator (CAISO) identified various typographical errors, transcription inaccuracies between tables and testimony text, certain areas of the testimony that required further clarification and other items that require correction. With this Errata, the CAISO is providing these corrections and clarifications.

There are three documents included with this submission. The first is an errata list of each correction being made to the testimony. The second document is a redlined version of the testimony incorporating the identified corrections. Finally, a redlined version of Attachment A to the testimony, containing one minor correction identified on the errata list, has been attached to this submission.

Respectfully submitted,

/s/ Judith B. Sanders
Judith B. Sanders

Attorney For The
California Independent
System Operator
Corporation

Errata 3/19/07

Page 2, Footnote 1

Replace Footnote 1 with

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

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

Page 7, Line 3

Change "LEAPS and Green Path North" to "(Green Path + LEAPS)"

Page 7, line 11

Insert the following sentence at the end of paragraph. "These estimates do not include ancillary services benefits that might be provided by the LEAPS project and assume that the full costs and benefits of both LEAPS and Green Path accrue to CAISO's ratepayers."

Page 8, line 11

Replace "Green Path + LEAPS" with "(Green Path + LEAPS)"

Page 12, line 20

Replace "that's" with "that"

Page 14, Line 1

Change "renewable energy" to "incremental renewable energy (in addition to the renewable energy output previously identified in GridView)"

Page 15, Line 7

Replace "Green Path" with "(Green Path + LEAPS)"

Page 16, Table 2.1, 3rd line

Change 1400MW to 1440MW

Page 17, line 15

Change "aim" to "aims"

Page 18, Line 7

Change "$7.08/MMBUT" to "$7.08/MMBtu"

Page 22, Line 12

Remove "and Green Path"

Page 22, Line 18

Replace "assumption" with "assumptions"

Page 23, Line 1

Change “Sunrise and (Green Path + LEAPS) cases, which cause” to “Sunrise case, which causes”

Page 23, Line 2

After “capacity,” insert “beyond the avoidance of the 565 MW of CTs required in the Base Case,”

Page 23, Line 5

Insert new bullet point

- For the (Green Path + LEAPS) case the CAISO assumed that the project would avoid the need to add an estimated 565 MW of CT’s that are required in the Base Case, but would not reduce the RMR capacity requirement in the area.

Page 25, Line 4

Change “Sunrise” to “South Bay”

Page 25, Line 10

Eliminate extra “.”

Page 25, Line 17

Replace “Green Path + LEAPS” with “(Green Path + LEAPS)”

Page 25, Lines 18 and 19

Replace sentence with

“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.”

Page 27, Line 20

Insert “requirement” between “capacity” and “reaches”

Page 28, Line 19

Change “Sunrise and Green Path cases that assume” to “Sunrise case that assumes”

Page 30, Line 11

Change “$62” to “$71”
Change “$69” to “$79”

Page 31, Line 16-17

Replace:

“The updated SSG-WI data already included approximately 33.3 TWh/year of renewable generation serving California loads today and, after minor”

With:

“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"

Page 32, Line 4

Insert the following new sentence at end of paragraph.

"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."

Page 36. Line 17

Change "RPC" to "RPS" and remove "."

Page 37, Table 3.2, Column G heading

Change "Sunrise" to "(Green Path + LEAPS)"

Page 38, Line 7

After the word "case" insert "has"

Page 38, Line 14

Insert the following new sentence at end of paragraph:

"Again, these results exclude any analysis of ancillary services benefits that might be provide by LEAPS or other alternatives."

Page 41, Line 6

Insert following new paragraph.

"The most significant benefit from Sunrise is the estimated $146 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 million per year. The total estimated annual benefits is $239 million, which is $82 million more than the estimated $157 million levelized annual cost of the Sunrise project.

Page 41 Table 3.5

Change D10 from "10" to "-"
Change G10 from "(10)" to "-"
Change D12 from "213" to "204"
Change G12 from "63" to "73"
Change G13 from "73" to "83"
Change D15 from "10,471" to "10,461"
Change G15 from "(125)" to "(115)"
Change A16 from "7,584" to "5,321"
Change B16 from "7,537" to "5,263"
Change C16 from "7,584" to "5,321"
Change D16 from "7,544" to "5,264"
Change E16 from "47" to "58"

Change G16 from "40" to "57"
Change A16 from "17,930" to "15,667"
Change B16 from "17,859" to "15,585"
Change C16 from "17,899" to "15,636"
Change D16 from "18,015" to "15,725"
Change E17 from "71" to 82"
Change G17 from "(85)" to "(58)"

Page 45, Table 4.1
Change "Case 3. Greenpath" to "Case 3. (Green Path + LEAPS)"

Page 45, Table 4.1
ADD NOTE BELOW TABLE:
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.

Page 45, Line 9
Change "Green Path + LEAPS" to "(Green Path + LEAPS)".

Page 45, Line 9
Add the following two sentences at the end of the paragraph:
"Note that these figures include transmission costs. To avoid double counting, Table 3.2 shows the adjusted RPS procurement costs net of transmission costs."

Page 53, Line 17
Change "Green Path" to "(Green Path + LEAPS)"

Page 53, Line 18
Change "585 MW" to "625 MW"

Page 54, Table 4.5
Change Resource Cluster "Imperial – Greenpath" to "Imperial (Green Path + LEAPS)"
Change Transmission Capital Cost ($MM) for Northeast CA from "$21" to "$152"

Page 54, Table 4.5 ADD NOTE BELOW TABLE:
"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."

Page 55, Line 4
Change "Green Path" to "(Green Path + LEAPS)"

Page 57, Line 9

Change ‘Imperial” to “Imperial - Sunrise”
Change “Green Path” to “Imperial - (Green Path + LEAPS)”

Page 59, Line 17
Add the following sentence at the end of the paragraph:
“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.”

Page 61, Line 22
Change “Green Path” to “(Green Path + LEAPS)”

Page 64, Line 7
Change “Green Path” to “(Green Path + LEAPS)”

Pages 64, 65 and 66, Table 4.6, 4.7, and 4.8 titles
Change “Resource” to “Incremental resource potential”

Page 64, Table 4.6 ADD NOTE BELOW TABLE:
“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.”

Page 65, Table 4.7
ADD NOTE BELOW TABLE:
“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).”

Page 65, Lines 9-10
Change “Green Path + LEAPS to “(Green Path + LEAPS)”

Page 66, Table 4.8, titles and body of the table (3 occurrences)
Change “Green Path” or “Greenpath” to “(Green Path + LEAPS)”

Page 66, Table 4.8
ADD NOTE BELOW TABLE:
“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.”

Page 67, Line 11
Change “565” to “435”

Page 69, Lines 3 through 20 replace entire Answer with:
“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."

Page 69, Line 23

Replace "The conclusions are as follows:" with:
"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."

Appendix A, Table A.1 Item 1, SDG&E Load Forecast

Remove "X" in Δ from SDG&E column.

Appendix A, Table A.1, Item "Gas price differentials"

Remove "[check this with Irina]" from the SDG&E column.

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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'

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[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

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- Updated Base Case~~, which reflects the updated Devers-Palo Verde 2 plan of service, updates to the maximum capacity of the existing CTs, and updates to the 2015 demand forecasts;~~
- Alternative 1: ~~Green Path + LEAPS, which is the updated Base Case the Green Path North project and the LEAPS project with Sunrise;~~Sunrise
- Alternative 2: South Bay~~, which is the updated Base Case plus the South Bay generation facility repowered with a new 620-MW combined cycle generating facility; and~~
- Alternative 3: ~~(Sunrise, which is the updated Base Case plus Sunrise.~~Green Path + LEAPS)

that it was critical to review SDG&E's changes and update the data and 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

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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.

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, 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 million when compared to the base case in 2015 and a relatively large positive benefit of $205 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 million per year. The levelized benefits are composed of $181 million in annual energy and reliability benefits and $58 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 ~~LEAPS and Green Path North~~(Green Path + LEAPS)?**

A. The South Bay case has comparatively low energy and reliability benefits of $41 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 million per year. The (Green Path + LEAPS) case has $83 million per year in energy and reliability benefits and $57 million in annual RPS procurement benefits. After subtracting $198 million per year in transmission costs, the total net benefit is negative: [-$58] million per year. These estimates do not include ancillary services benefits that might be provided by the LEAPS project and assume that the full costs and benefits of both LEAPS and Green Path accrue to CAISO's ratepayers.

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~~'s~~ 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	~~1400MW~~ 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~~UT~~ (= $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.

[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 public workshop 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 ~~and Green Path~~ 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 ~~and (Green Path + LEAPS) cases, which cause~~ 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 that the project would avoid the need to add an estimated 565 MW of CT's that are required in the Base Case, but would not reduce the RMR capacity requirement in the area.

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 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 the same as the ~~Sunrise~~ 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 million per year for Sunrise, $51 million per year for South Bay, and $51 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 2015 (nominal dollars) are $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 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 pre-dispatch payment in your analysis.

A. The annual RMR operating benefit is the difference between the pre-dispatch costs in the Base Case and the alternate cases. 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 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 and beyond. The RMR requirement is 65 MW less each year prior to 2015.

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.

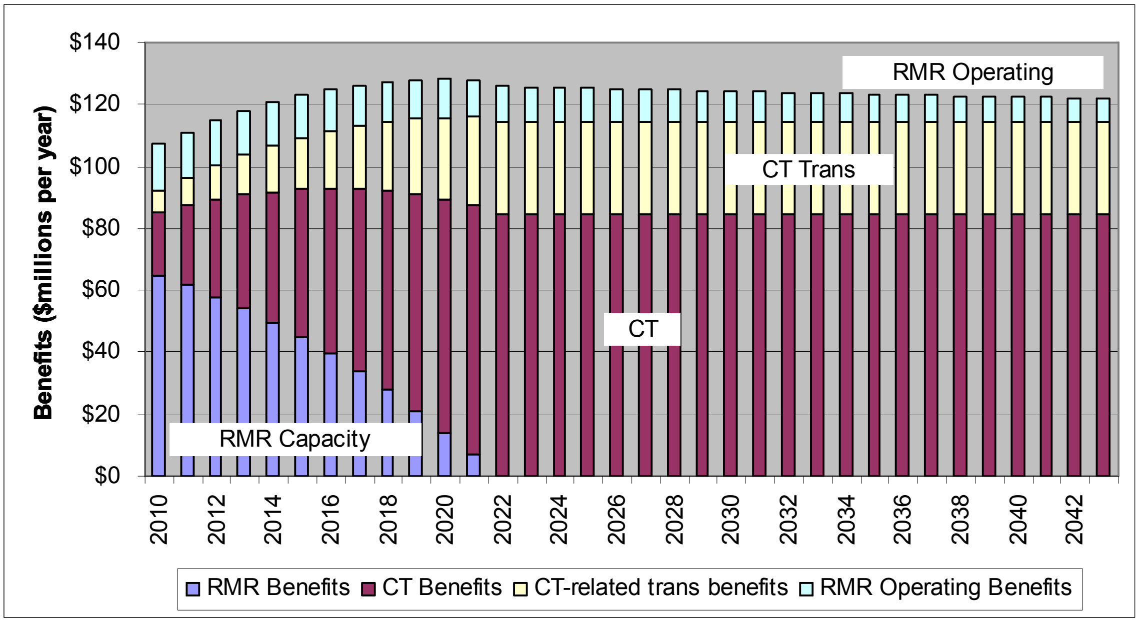
For the Type 1 contract price, the CAISO assumes that the payment level would be no higher than the Type 2 payments in the presence of transmission import capability in excess of in-area CT displacement. Accordingly, the Type 1 payments only apply in the Sunrise ~~and Green Path~~ case~~s~~ that assumes a 2010 in-service date for the new transmission. For year 2010, the CAISO assumes that the new import capability 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.

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

A. The annual reliability benefits are shown in constant dollars in Figure 2.1. The RMR capacity benefits decline rapidly as the quantity of RMR capacity approaches the 1440 MW limit, and the price of that capacity approaches the full Type 2 price 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.

[7] From the EIA Energy Outlook 2005

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 2020: $156
- South Bay 2015: $42 2020: $46
- (Green Path + LEAPS) 2015: $~~62~~71 2020: $~~69~~79.

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~~The updated SSG-WI data already included approximately 33.3 TWh/year of renewable generation serving California loads today and, 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 ~~RPC~~ 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 ($M)	Sunrise Transmission in RPS Costs	Adjusted RPS Cost ($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**

		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 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 million per year in 2015 to negative $18 million.

The South Bay case has low energy and reliability benefits of $43 million, but the transmission costs are even lower at $9 million. The net benefit is $33 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 million in energy and reliability benefits, offset by $198 million annual transmission cost. The net benefit is negative $118 million per year in 2015, and declines to negative $146 million per year 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.

	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	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 assumption, Table 3.4 shows that the total energy and reliability benefits for the Sunrise case is $190 million, which is greater than the Sunrise project cost of $157 million. The RPS procurement benefit is $172 million, so the total net benefit of the Sunrise case is $205 million per year in 2020.

The South Bay case has low energy and reliability benefits of $46 million, but the transmission costs are even lower at $9 million. The net benefit is $37 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 $89 million in energy and reliability benefits, offset by $198 million annual transmission cost. The net benefit is negative $109 million per year in 2020. The RPS procurement benefit is $172 million, so the total net benefit of the (Green Path + LEAPS) case increases to a positive $63 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	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 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 million per year. The total estimated annual benefits is $239 million, which is $82 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 million. The net benefit is $32 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 million in energy and reliability benefits. Subtracting the transmission project costs, the net benefit becomes negative $115 million per year. The levelized RPS procurement benefit is $57 million, so the total net benefit remains negative at -$58 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				**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	-	-	-	10	-	-	(10)
11	RA Costs to replace CTs and RMR contracts	-	-	-	-	-	-	-
12	**Subtotal Reliability Cost and Benefit**	276	131	236	213	**146**	**40**	**63**
13	**Total Energy and Reliability Benefits**					**181**	**41**	**73**
	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	10,471	**24**	**32**	**(125)**
	RPS Procurement Cost							
16	Adjusted RPS Cost	7,584	7,537	7,584	7,544	**47**	**-**	**40**
17	**Total Costs and Benefits**	17,930	17,859	17,899	18,015	**71**	**32**	**(85)**

	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 SDG&E's corrected levelized value 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. We have no basis for challenging their correction. Our other transmission costs are unchanged.

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 billion; Case 1, Sunrise: $6.678 billion; Case 2, South Bay: $6.685 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	$ -	$ 6,685	$ -	$ 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.

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. Greenpath	$ 4,336	$ 211	$ 6,696	$ 12	$ 5,447	$ 127

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 billion; Case 1, Sunrise: $5.428 billion, Case 2, South Bay: $5.321 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?

[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.

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

[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 (~~585~~ 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	$21	$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	$49.74
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?

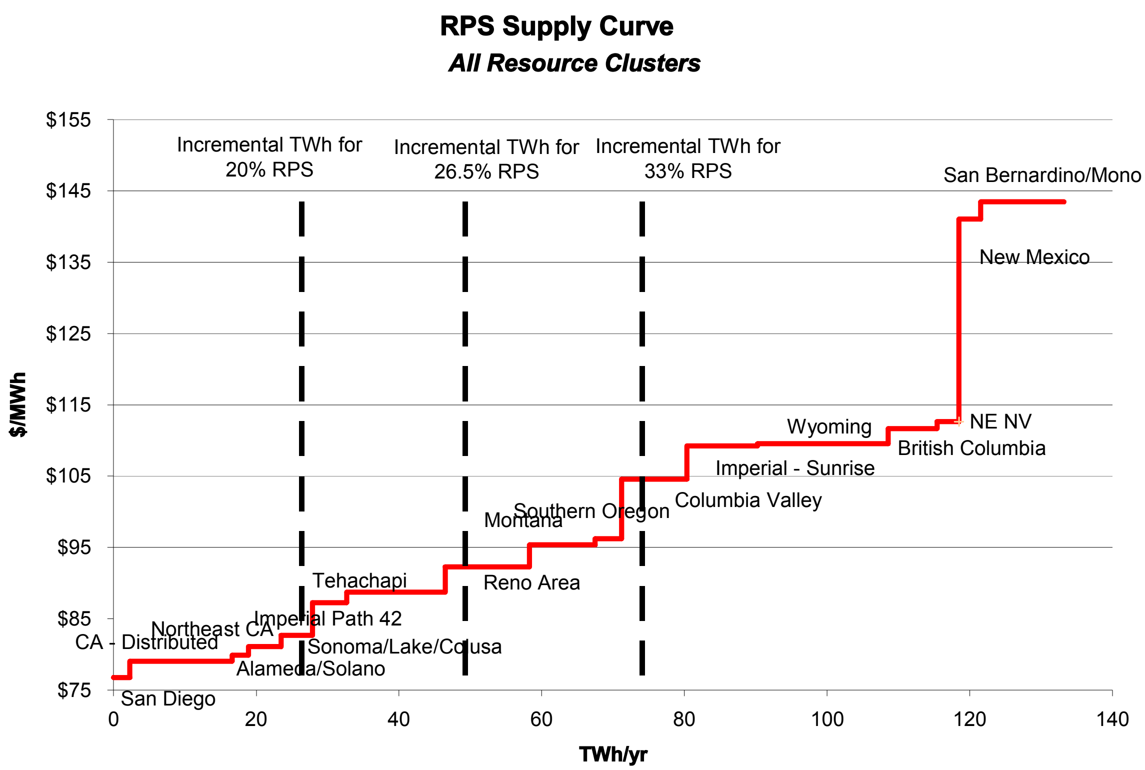
A. No. The assumption that transmission costs are based on nameplate generating capacity while energy transfers are calculated using average capacity factors results in somewhat higher costs for low-capacity-factor resources such as wind relative to alternative assumptions. However, this is largely, 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.

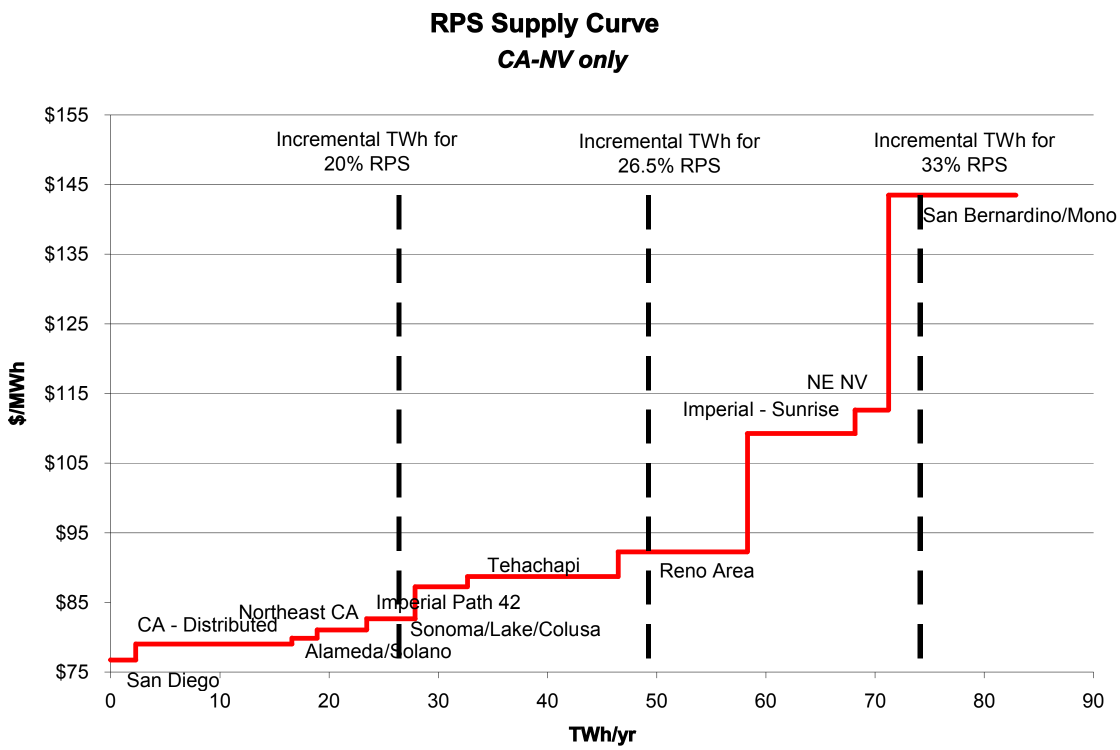
Q. Does this modification have a substantial impact on the estimated cost of RPS compliance?

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?

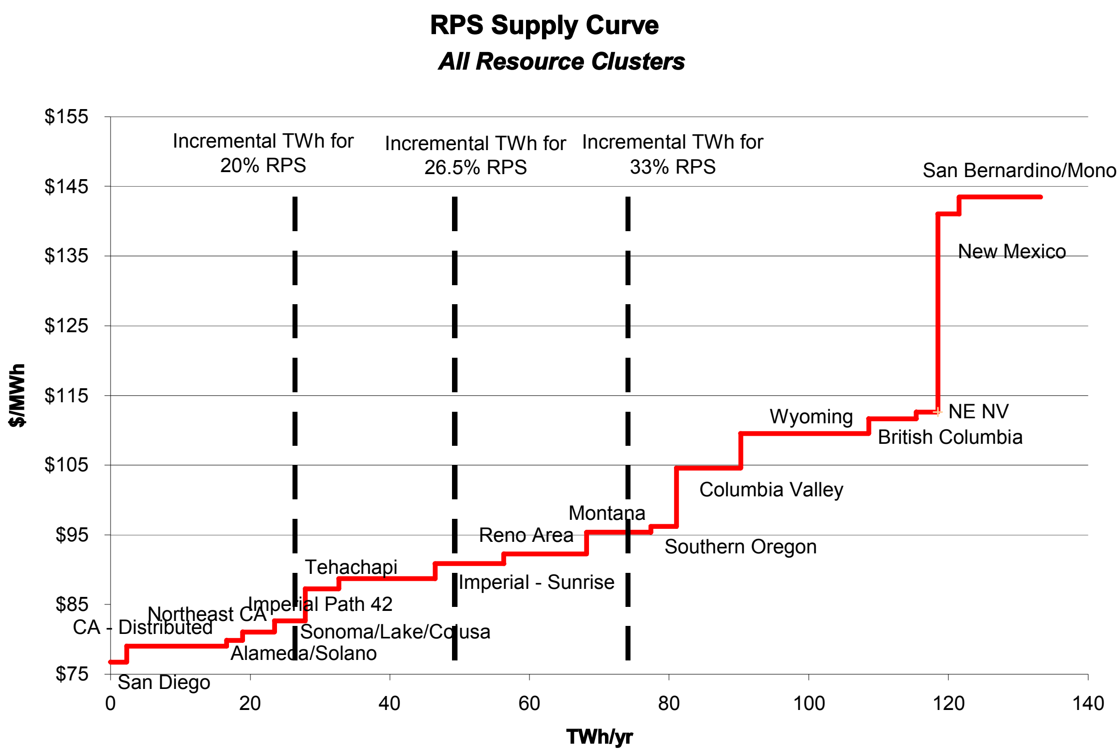
A. No. The renewable resources that have been developed or are under development by California LSEs in order to comply with the 2010 target are not always the least cost projects shown in Figure 4.1, as permitted by current state policy. For instance, projects are currently under development for wind 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 billion in 2020.

Table 4.6. Incremental r~~R~~esource 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 $/MWh	Cumulative Available Energy (TWh)	Cost Included in 2015 RPS ($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 million lower than the Base Case in 2020.

Table 4.7. Incremental r~~R~~esource 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 $/MWh	Cumulative Available Energy (TWh)	Cost Included in 2015 RPS ($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 million higher than the Base Case in 2020.

Table 4.8. Incremental ~~R~~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 $/MWh	Cumulative Available Energy (TWh)	Cost Included in 2015 RPS ($MM)	Cost Included in 2020 RPS ($MM)
Imperial -Greenpath	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**

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 ~~565~~ 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 565 MW of CTs are not required because in-area resource needs would be met by imports However, all generation in the San Diego load pocket would 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)							157	565
SDG&E SYSTEM LOSSES (MW)	98	135	98	138	106	215	97	155
TOTAL SDG&E IMPORT (MW)	**3009**	**3045**	**2448**	**2488**	**3016**	**3125**	**2850**	**2500**
Surplus (MW)	**991**	**455**	**402**	**12**			**0**	
Total Import Capability (MW)	4000	3500	2850	2500	N/A	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 ~~reactive~~ modeling issues ~~associated~~ that were the most pronounced during ~~with~~ the simultaneous loss of two ~~Nuclear~~ 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. ~~, which are traditionally the most severe contingencies from a voltage stability perspective, for the 2015 cases. The CAISO has added the following reactive support for all four cases to achieve acceptable study results for the loss of two Nuclear generating units:~~

- ~~800 MVAR at Malin Substation~~
- ~~150 MVAR at 69kV Del Norte Substation~~
- ~~15 MVAR at Walker B 69kV Substation~~
- ~~500 MVAR at Midway 500kV Substation~~
- ~~500 MVAR at Imperial Valley 500kV Substation~~

~~The above reactive support was modeled to obtain acceptable power flow solution for the loss of the two Nuclear generating units for the four updated CAISO power flow cases. The above reactive support requirements could be further optimized to achieve acceptable system performance.~~

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 concern with the Sunrise Project 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. 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 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 230 kV 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.

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.

Appendix A: GridView Inputs

This table summarizes the GridView input assumptions used by the CAISO in developing the Base Case. The second column contains an "X" in those instances where the CAISO has changed the input since the CAISO's January 26, 2007 testimony. The third column contains an "X" in those instances where the CAISO is aware of a difference between its input and SDG&E's input. The table is not intended to be exhaustive in identifying all differences in GridView inputs.

Table A.1

Item	CAISO Change	Δ from SDG&E	**CAISO**	**SDG&E**
Load Forecast				
SDG&E	X	~~X~~	CEC June 2006	Same as CAISO
PG&E and SCE Zones	X	X	CEC June 2006 Load Forecast	CEC Sept 2005 load forecast
IID		X	2015 = 3,916 GWh (includes losses)	2015 = 6,215 GWh
LADWP control area		X	2015 = 30,583 GWh (includes losses)	2015 = 33,315 GWh
Other CA utilities		X	CEC June 2006 Load forecast	CEC Sept 2005 load forecast
Other WECC		X	SSG-WI August 2006 database, which contains January 2006 load assumptions	January 2006 WECC economic database.
Uncommitted energy efficiency			332MW	332MW
Distributed Generation			74MW	74MW
California Solar Initiative		?	SDG&E: 300MW of installed (150 MW of dependable) roof top solar at approximately 18% capacity factor. PG&E and SCE: 1350 MW each of installed (675MW of dependable) roof top solar at approximately 18% capacity factor. For PG&E, 25% is installed in the Bay zone, and 75% is installed in the Valley zone.	150MW
Losses - GridView	X		Transmission losses were removed from the load forecasts by reducing the load forecast by 3.5%. Transmission losses are dynamically calculated by Gridview.	Transmission losses included in the load forecasts.
Natural Gas Cost				
Base Price at Henry Hub		X	$7/MMBTU ($2015), same as WECC Database nominal 2006 values.	$7/MMBTU ($2006), so $9/MMBTU ($2015)
Gas price differentials	X	X	Volumetric transportation costs added for Southern California for schedules GT-F and G-SRF (Total = $0.3935/MMBTU); for PG&E backbone service ($0.1651/MMBTU). Added Arizona tax on use by electric generators (5.6%)	CA, NV, Sierra, Mexico, and So Colorado higher by 3.4% (compared to CAISO). $0.435/MMBTU price difference with AZ. ~~[check this with Irina]~~

Item	CAISO Change	Δ from SDG&E	**CAISO**	**SDG&E**
Transmission Configuration				
Network Representation		X	Differs from SSG-WI, which is based on a 2015 power flow with the following incremental transmission: Tehachapi Wind transmission 4 Corners to Phoenix Pinal project	WECC 2008 Heavy summer power flow case with the following incremental transmission: Palo Verde - Devers #2 Tehachapi Wind transmission - 2 lines Navajo/Desert Rock; Four Corners - Moenkopi Moenkopi to Market Place Coronado to Silver King line w/ series comp 4 Corners to Phoenix West of Devers Capacity upgrade at N. Gila Pinal project Amps phase shifter Increase Montanan to Northwest transfer by 750MW Wyoming to Utah to integrate Bridger #5 and Sw WY wind SF Bay area project Imperial 500kV line (one to LA, one to SD) Kansas to Colorado to integrate 2-700MW coal Reconfigure Sylmar to SCE
Network Topology			Same as SDG&E	WECC 22-bubble topology adjusted as follows: single NW bubble split into two; single PG&E bubble split into two, RMATS topology used for the Rocky Mountain states, except Montana bubbles are reduced from two to one.
Tehachapi transmission upgrade		X	Yes, fully modeled in all cases	Minimal Tehachapi transmission upgrades included
Tehachapi incremental resources		X	4350MW, 612MW thermal	1400MW
Wheeling Rates			Not included	Not included
Miguel Transformer Loading Limit	X		Not modeled in runs prior to Feb 2007. Not in the SSG-WI database. CAISO adding back in for new runs to reflect current operations.	Modeled. Limits flow on Imperial Valley - Miguel 500kV line minus 38% of Imperial Valley Generation to <= 1450MW.
San Diego Import Limits			Modeled through import interface limits	Modeled through import interface limits
SCIT/East of River Nomogram		X	Not Modeled. Not in the SSG-WI database.	Modeled. Sunrise added to SCIT, but SCIT limits not increased.
Navajo-Crystal and Moenkopi-Eldorado ratings		X	SSG-WI database ratings.	Higher ratings.
Alternative renewable scenario and congestion upgrades			Modeled alternative renewable scenario in Reference case and South Bay case, along with transmission upgrades suitable to eliminate congestion clearly assignable to alternative renewables.	SDG&E did not consider an alternative renewable scenario in their Gridview runs

Item	CAISO Change	Δ from SDG&E	**CAISO**	**SDG&E**
Generator Information				
Heat Rates for existing generators		X	August 2006 WECC Database	Started with January 2006 WECC Database. Heat rates for 17 plants replaced with data from CEC's aging power plant study. Heat rates for four newer vintage plants changed to be about 7100.
	X		Dual fuel allowed in 1/26/07 runs. Dual fuel removed for Pittsburg.	Pittsburg units not allowed to burn oil
CAISO customer ownership				
LEAPS1		X	100%	0%
LEAPS2		X	100%	0%
LEAPS3		X	100%	0%
BOREL_1		X	100%	0%
LAKEGEN_1		X	100%	0%
OtayGT1		X	100%	0%
OtayGT2		X	100%	0%
OtayST1		X	100%	0%
HumBay1-1		X	100%	0%
HumBay1-2		X	100%	0%
KESWICK_9		X	100%	0%
COTTONWD_8		X	100%	0%
MELONES_7		X	100%	0%
MENDOCNO_5		X	100%	0%
TBL MT D_5		X	100%	0%
TUOLUMN_6		X	100%	0%
SHASTA_8		X	100%	0%
SN LS PP_8		X	100%	0%
FULTON_3		X	100%	0%
WHEELER_2		X	100%	0%
GLENN_3		X	100%	0%
GOLDHILL_3		X	100%	0%
MTNVWCS1_1 (Wind)		X	0%	100%
MTNVWCS2_1 (Wind)		X	0%	100%
RVCANAL1_1			0%. Retired and removed from case	100%
RVCANAL2_2			0%. Retired and removed from case	100%
RVCANAL3_3			0%. Retired and removed from case	100%
RVCANAL4_4			0%. Retired and removed from case	100%
AESPlac1		X	0%	100%
Etiwand3		X	0%	100%
Etiwand4		X	0%	100%
EA551CT and ST (6 total)		X	Not in ISO scenarios. Replaced by merchant generation from the queue - 0%	100%

Item	CAISO Change	Δ from SDG&E	**CAISO**	**SDG&E**
New Generators				
Majority of new plants		X	Start with SSG-WI. Some generic generation in SSG-WI left in place, but where possible the CAISO replaced generic generation with generation from the queue. As needed, the CAISO adjusted bus locations, heat rates and O&M based on queue information for plants judged to have more than 50% probability of being built. For PG&E plants, CAISO relied upon PG&E's contract group (procurement plan). For SCE, the CAISO used the projects that SCE is actively working on in the queue. For SDG&E, the CAISO used actual plants that SDG&E will own (e.g.: Otay Mesa).	SDG&E added generation for two signed PPAs in SD.
Changes to Generic Plants		?	45 MW EnvirePk project removed because of cancellation	
		X	425 MW of generic RPS projects not modeled	
		X	480 MW generic biomass, replaced by gen in the queue	
		X	4548.5 MW generic gas, replaced by generation in the queue	
		X	635MW generic geo replaced by generation in the queue	
		X	780MW generic solar replaced by generation in the queue	
		X	463MW generic wind replaced by generation in the queue	
		X	75MW replaced by Salton Sea geothermals	
		X	3500MW Tehachapi wind gen, replaced by detailed model	
		X	300MW had different bus number, 900 MW	
Palo Verde Units	X	X	SSG-WI 2700 MW of CTs changed to CCGTs prior to Feb 2007. New runs use original SSG-WI CT designations.	2500MW of CCGT, 200MW of CT.

Item	CAISO Change	Δ from SDG&E	**CAISO**	**SDG&E**
Other Inputs				
Strategic Bidding		X	No	Yes
Salton Sea geothermal O&M Cost		X	**REDACTED**	**REDACTED**
SoCal congestion rents included in economic analysis			Yes	Yes
NorCal congestion rents included in economic analysis		X	Yes	No
RMR Contracts			Not modeled in GridView runs.	
Other Changes or Differences				
Losses - Reliability	X		Losses were inadvertently double counted for SDG&E's reliability analysis. This has been corrected in the February 2007 analyses	Not an issue for SDG&E
Return of excess losses payments		X	Yes	No
Exclusion of non-CAISO participants from IOU zones	X	X	Consumer payment and congestion rent benefits were reduced for non-TAC customers in the IOU zones modeled in GridView. The exclusion was 2.4% in Jan 2007 runs. This has been corrected to 23.1% for the PG&E zones and 0.4% for SCE (The average across all three IOUs is 11.7%)	Consumer payment and congestion rent benefits based on entire load within IOU zones.

CERTIFICATE OF SERVICE

I hereby certify that I have served, by electronic and United States mail, a copy of the foregoing Errata to the Initial Testimony of The California Independent System Operator Corporation, Part 2 to each party in Docket No. A.06-08-010

Executed on March 23, 2007 at Folsom, California.

/s Charity N. Wilson
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An Employee of the California
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