California ISO
Your Link to Power

California Independent
System Operator Corporation

May 21, 2010

Re: **<u>California ISO Planning Reserve Margin Study – 2010 – 2020</u>**

To All Interested Parties in R. 08-04-012:

The California Independent System Operator Corporation provides the attached *Final Report to California Independent System Operator for Planning Reserve Margin Study – 2010 – 2020* (henceforth "the Study") as an extension to the *Final Report to California Independent System Operator for Planning Reserve Margin Study – 2010*, which was made available in December 2008, pursuant to the California Public Utilities Commission's Rulemaking (R.) 08-04-012.

The Study informs the ISO, the CPUC, Load Serving Entities and other stakeholders of the installed capacity requirements necessary to maintain a 1 day in 10 years (or 0.1 days per year) loss-of-load expectation (LOLE), based on the annual reserves calculated using the coincident peak loads of the areas. To determine this LOLE based planning reserve margin (PRM), the generation system reliability for the ISO was calculated at various levels of installed reserve margins in order to determine the reserves required to maintain the industry standard of 0.1 days[1] per year reliability metric. The primary tool used for this study was GE Energy's Multi-Area Reliability Simulation program (MARS).

The Study, which was performed in 2009, builds on the data and results of the 2008 study, and considers a revised base case and additional scenarios for 2010, 2015 and 2020. The sensitivities for 2010 included the effects of extreme hydro conditions, extreme loading conditions, and the impact of increased unit forced outage rates. For 2015 and 2020, the additional sensitivities included extreme hydro conditions, adjusted availability of the once-through-cooling (OTC) generating units, and interconnection of sufficient renewable resources to meet a 33% RPS.

The ISO is hopeful that the current study will assist in bringing Phase 1 of R. 08-04-012 to conclusion, and possibly help in determining whether to open a new proceeding focused on some of the remaining methodological questions and policy issues not addressed in the Study. Consistent with the views of the CPUC,[2] the ISO believes that the analysis would need to be updated to reflect changes in some data and scenario assumptions to make it more consistent with developments in State policy as well as results from ISO operational studies and possibly other recent resource and transmission planning analyses by various entities. Some of these considerations are discussed next.

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[1] 0.1 days per year LOLE is reliability metric for resource adequacy planning at major RTO/ISOs in the Eastern Interconnection.
[2] See, CPUC, Energy Division Proceeding Status Update and PRM Modeling Manual R.08-04-012, February 3, 2010, available at
http://docs.cpuc.ca.gov/WORD_PDF/REPORT/113222.PDF.

First, one key area of interest to the ISO and other stakeholders is the possible impact of required operational characteristics to integrate renewable resources on future capacity needs. As noted in the Study (e.g., pages ES-1, 27 and 33), the determination of the PRM is based on the installed capacity needed for serving peak demand only, and does not address the more granular operational requirements associated with the integration of renewables. The ISO anticipates a number of characteristics will be required from the future generating fleet, such as quick start capability, more flexible lower operating limits, increased intra-hour ramp needed for additional load following, increased procurement of regulating reserves, and possibly additional spinning and non-spinning reserve capacity. The ISO is currently conducting several types of scenario-based analyses of 20% and 33% RPS that aim to inform these operational needs, including statistical models that simulate load-following and regulation requirements, and production simulations that evaluate the capability of existing and future generation to provide the needed capabilities. The ISO anticipates that these studies will not only help define the operational characteristics that generation and non-generation capacity should provide under high renewable scenarios, but also may require adjustment of the PRM to reflect capacity needed to serve these operational needs. Release of further operational results is anticipated to be ongoing throughout much of 2010.

Second, as observed in the Study, OTC unit retirements and their replacements are an important sensitivity for PRM determination, as well as for the operational requirements for renewable integration (i.e., whether OTC units that provide the needed operational flexibility are assumed to be repowered or replaced by largely operationally equivalent generating units or other non-generation resources). The OTC modeling for determining PRM in particular years can be enhanced in the future by the actual schedule imposed by the State Water Resources Control Board.

Third, a key assumption in the Study is the capacity value of the renewable resource mix, especially by 2020. There are two further examinations of this assumption that could be considered: the first of the capacity value itself, , and the second of alternative mixes and locations of renewable resources. As observed by the CPUC,[3] and noted above with respect to the ISO operational studies, the analysis of future renewable resources is currently being undertaken on a scenario basis. This is to reflect uncertainty about the location (within and outside California) and technology mix in 2020 and hence should inform the determination of the PRM, particularly as noted in the Study, by the 2020 time-frame or earlier. Examples include the scenarios provided by the CPUC in its 2009 implementation analysis of the 33% RPS (one of which, the 33% RPS Reference Case, was the 2020 renewable portfolio modeled in the Study) and the scenarios modeled recently by the California Transmission Planning Group.[4] The ISO notes that the 33% RPS "net short" (i.e., incremental renewable energy needed to meet the 33% RPS) calculated for the Study was determined using the CEC's 2007 load forecast due to the need for assumptions to perform the studies prior to adoption of the new demand forecast by the CEC in late 2009, while subsequent analyses using this same scenario (such as the ISO's 33% RPS operational study) have re-calculated the net short using the CEC's 2009 load forecast, resulting in less renewable capacity on-line in 2020. In addition, the CPUC will promulgate updated 33% RPS scenarios in July 2010 in its Long-Term Procurement Planning (LTPP) proceeding. A future application of the Study methodology could thus be to update renewable capacity values and examine the impact on PRM of alternative renewable scenarios, including variations in the net short.

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[3] Op cit, pp. 18-19.

[4] See www.ctpg.us.

values and examine the impact on PRM of alternative renewable scenarios, including variations in the net short.

Finally, the ISO notes that on pages ES-1, 27 and 33, the report refers to data on the 33% RPS supply case provided as part of the "Unified Vision" initiative. That initiative, which is a joint effort of the CPUC, CEC, the California Air Resources Board, the California Environmental Protection Agency, and the ISO, has been renamed the "California Clean Energy Future" initiative. Further public updates on this initiative are expected in Q2 2010.

In summary, the ISO is pleased to submit this report as a demonstration of alternative, probabilistic methods for calculating PRM, and looks forward to continuing to work with the CPUC in determining the required quantity of installed capacity by refining an appropriate PRM methodology that reflects the needed operational characteristics of existing and future supply and demand resources.

Sincerely,

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GE Energy

Final Report to
California Independent System Operator
for
Planning Reserve Margin (PRM) Study – 2010 - 2020

Prepared by

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April 13, 2010

Foreword

This document was prepared by General Electric International, Inc. It is submitted to the California Independent System Operator (CAISO). Technical and commercial questions and any correspondence concerning this document should be referred to:

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Legal Notices

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Executive Summary

This study is an extension of the *Planning Reserve Margin (PRM) Study – 2010* that was conducted in 2008 to provide guidance to CAISO and CPUC in establishing the Planning Reserve Margin (PRM). The PRM is the reserve margin that is required to maintain the CAISO system at a given level of reliability as expressed in terms of a daily loss-of-load expectation (LOLE) of 0.1 days/year.

Cautionary Note

It is important to note that a PRM study such as this one is intended to address only the energy supply issue in terms of the amount of installed capacity required to meet a specific reliability metric, such as an LOLE of 0.1 days per year, which is an industry standard accepted at most major Regional Transmission Organizations (RTOs), ISOs, and other reliability organizations. **The PRM study does not address operational issues**, local reliability requirements, or issues related to the integration of renewables. The ancillary services required to integrate the renewable generation (e.g., ramping, regulation, load following, etc.) may very well require the presence of a larger fleet of generation than that required for energy service purposes as determined by the PRM. Based on the results of CAISO's *Integration of Renewable Resources* study conducted in 2007, (http://www.caiso.com/1ca5/1ca5a7a026270.pdf), all of the existing generating resources within the ISO Balancing Authority Area are needed to provide operational support to meet the State's 20% Renewables Portfolio Standard (RPS) mandate, and possibly more generating resources are needed to meet the State's 33% RPS target. The ISO is currently evaluating the operational needs to meet the State's 33% RPS target.

It also is worth noting that the PRM study is not based on the actual behavior of the wind generation in the three summer months but the data inputs are based on hourly generation profiles provided by National Renewable Energy Lab (NREL) for the location, type, and their corresponding capacity provided by E3/CPUC as part of the "Unified Vision" for 33% RPS target in 2020. Though apparently NREL's characteristics of renewable profiles can be considered optimistic in nature, with more than 70% of the renewable additions having profiles that yield an annual capacity factor more than 39%, NREL engineers justified their calculated value on good wind speed and new wind turbine design that can start producing at a lower wind speed as well as can sustain higher wind gusts.

This study builds on the data and results of the 2008 PRM study[1] to consider a revised Base Case and additional scenarios for 2010 as well as for 2015 and 2020. The sensitivities for 2010 included the effects of extreme hydro conditions, extreme loading conditions, and the impact of increased unit forced outage rates. For 2015 and 2020, the additional sensitivities included extreme hydro conditions, unavailability of the once-

[1] The ISO commissioned the 2008 PRM study, which was coordinated in the CPUC Order Instituting Rulemaking (OIR) on the PRM in the 2008 time frame.

through-cooling (OTC) generating units[2], and increased penetrations of renewable sources of generation such as wind and solar.

To determine the PRM, the generation system reliability for CAISO was calculated at various levels of installed reserve margins in order to determine the reserves required to maintain the specified level of system reliability. The primary tool used for this study was GEII's Multi-Area Reliability Simulation program (MARS).

In the 2008 study, the calculation of reserve margins on a monthly basis was the primary method used, although a number of sensitivities were run using other methods. **All of the simulations in the current study were based on the annual reserves calculated using the coincident peak loads of the areas. In addition, the current study modeled a total of 7,310 MW[3] of imports from external systems that provided reliability benefit to the CAISO system but were not included in the reserve margin calculations[4].** These imports were not modeled in the initial simulations of the 2008 study per stakeholders' inputs at the time. These are significant changes that should be noted when comparing results between studies.

The CAISO LOLE and required capacity additions are summarized in Table ES - 1. The first three columns show the LOLE (days/year) for the "as-found"[5] system after the changes for that sensitivity had been made. For example, when the OTC units were removed, the LOLE became 7.562 days/year in 2020. The next two columns show the amount of "perfect" capacity (capacity with no planned or forced outages) or renewable capacity that had to be added to return the LOLE to the target of 0.1 days/year. 2020 was the only study year for which capacity additions were required, and only for the OTC and renewables sensitivities. Table ES - 2 shows the PRM required to maintain the system at 0.1 days/year.

The Base Case results indicate the need for a PRM in the range of 8% to 9% for the study period. These figures are based on an annual PRM requirement. The results of the 2008 study indicated that the monthly PRM would be about four percentage points more, in the range of 12% to 13%. Including just one-half of the imports (3,655 MW) in the reserve margin calculations would increase the annual PRM values to approximately 15%.

The expected unserved energy was 0 MWh/year for all cases except for the OTC retirements sensitivity in 2020 for which it was 51,743 MWh/year, and the 2020 renewables sensitivity for which it was 2,534 MWh/year.

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[2] Unavailability of OTC generation is a conservative study scenario for evaluating the system impacts of the proposed implementation policy from the State Water Resources Control Board.

[3] This amount of imports is in addition to the out-of-state generation (2,190 MW) that was included in the reserve margin calculations. The total imports modeled was 9,500 MW.

[4] These imports are available resources but only included if needed to meet a 0.1 days per year LOLE metric.

[5] The "as-found" system refers to the CAISO system as it is currently planned and projected for the study period, before any changes have been made to it for a specific sensitivity or to model a given level of installed reserves.

Table ES - 1 - Summary of LOLE and Required Capacity Additions

Case	LOLE of "As-Found" System With Sensitivity Changes and Without Replacement Power (days/year)			Capacity Added to Meet 0.1 days/year in 2020 (MW)	
	2010	2015	2020	Perfect	Renew-ables
Base Case with Load Forecast Uncertainty	0.000	0.000	0.000		
Base Case 1-in-2	0.000	0.000	0.000		
Base Case 1-in-5	0.000	0.000	0.000		
Base Case 1-in-10	0.000	0.000	0.000		
Base Case 1-in-20	0.000	0.000	0.000		
Base Case with 4 Load Models	0.000	0.000	0.000		
Extreme Load	0.000	0.000	0.000		
Extreme Hydro	0.000	0.000	0.000		
Extreme Load and Hydro	0.000	0.000	0.000		
Extreme Hydro without Carryforward	0.000	0.000	0.000		
25% Increase in EFORs	0.000				
OTC Retirements		0.000	7.562	6,774	
Renewables			1.126	2,970	8,250

Table ES - 2 - Summary of CAISO PRM (%)

Case	2010	2015	2020
Base Case with Load Forecast Uncertainty	8.1	8.5	8.7
Base Case 1-in-2	0.8	1.0	1.2
Base Case 1-in-5	6.7	7.1	7.0
Base Case 1-in-10	8.7	8.9	9.1
Base Case 1-in-20	10.4	10.7	10.8
Base Case with 4 Load Models	7.6	8.0	8.1
Extreme Load	10.4	10.7	10.8
Extreme Hydro	8.1	8.5	8.7
Extreme Load and Hydro	10.4	10.8	10.8
Extreme Hydro without Carryforward	9.2	9.4	9.4
25% Increase in EFORs	10.3		
OTC Retirements		8.3	6.7
Renewables			27.2

Modeling specific load forecast uncertainty through separate load models rather than multipliers on the 1-in-2 load model decreased the PRM by about one-half percentage point. The assumption of extreme load conditions, represented by the 1-in-20 load forecast, increased the PRM by approximately two percentage points, to the 10% to 11% range. A 25% increase in the forced outage rates had a similar effect. Assuming extreme hydro conditions had no impact on PRM, but not allowing the carry-forward of unused energy from month to month increased the PRM by about one percentage point. In the once-through-cooling (OTC) scenario, the retirement of units which were then replaced by units with lower forced outage rates resulted in a slight decrease in the PRM. In the case of the renewables scenario for 2020, the opposite effect was observed. Replacing thermal capacity with renewable additions that had a capacity value of only 36% significantly increased the PRM from 8.7% to 27.2%. This significant impact is shown in Figure ES - 1.

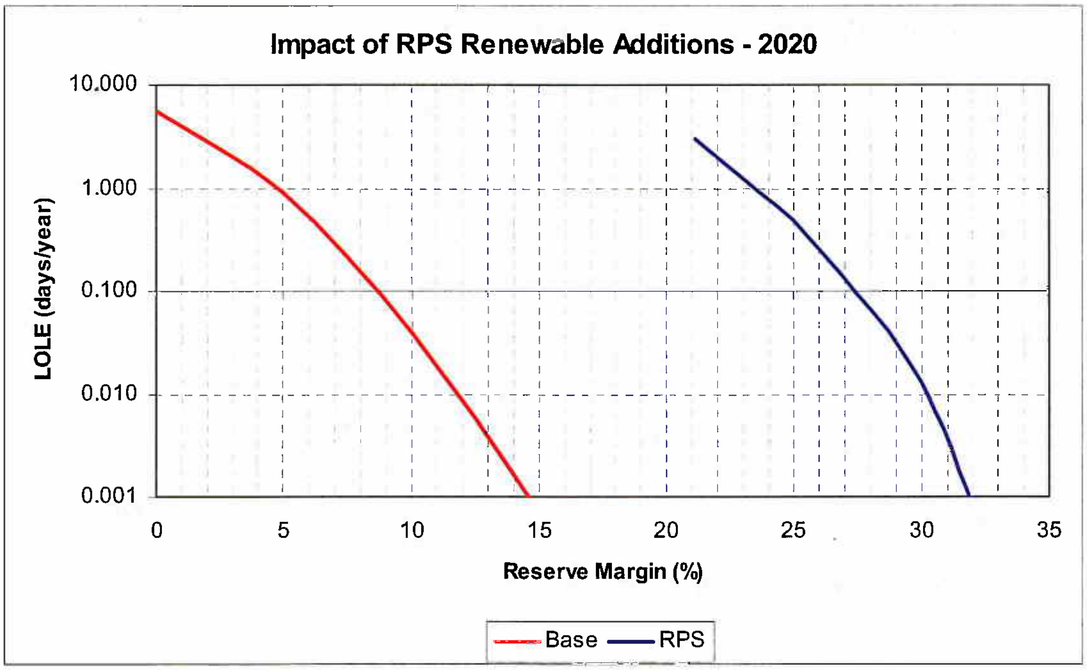


Figure ES - 1 - Impact of RPS Renewable Additions - 2020

1 Introduction

In late November 2007, the California Independent System Operator (CAISO) initiated a Planning Reserve Margin (PRM) stakeholder process, and held initial stakeholder meetings to review a preliminary study scope and proposals by potential vendors to perform a study. On April 10, 2008, the California Public Utilities Commission (Commission or CPUC) opened Rulemaking (R.) 08-04-012 "to review, and modify to the extent found to be appropriate, the Planning Reserve Margin (PRM) and the assumptions, methods, and procedures used for its determination."[6]

In 2008, at the urging of the CPUC, the CAISO and the CPUC merged their PRM stakeholder processes, which were run in parallel at the time, to provide affected parties and interveners a common forum for the evaluation of probabilistic generation reliability for calculating planning reserve margin requirements for resource adequacy assessment. The final report for this joint study effort was issued in December 2008.

The current study, performed in 2009, builds on the data and results of the 2008 study to consider a revised Base Case and additional scenarios for 2010 as well as for 2015 and 2020. The sensitivities for 2010 included the effects of extreme hydro conditions, extreme loading conditions, and the impact of increased unit forced outage rates. For 2015 and 2020, the additional sensitivities included extreme hydro conditions, unavailability of the once-through-cooling (OTC) generating units, and increased penetrations of renewable sources of generation such as wind and solar.

[6] *Order Instituting Rulemaking* (OIR), issued April 16, 2008 in R 08-04-012 at 17-18.

2 Methodology

MULTI-AREA RELIABILITY SIMULATION (MARS)

The Planning Reserve Margin (PRM) is the reserve margin that is required to maintain the CAISO system at a given level of reliability as expressed in terms of a daily loss-of-load expectation (LOLE). The generation system reliability for CAISO was calculated at various levels of installed reserve margins in order to determine the reserves required to maintain the specified level of system reliability of 0.1 days/year. The primary tool used for this study was GEII's Multi-Area Reliability Simulation program (MARS).

The daily LOLE is often defined as the expected number of days of insufficient capacity at the time of the daily peak load. Under this definition, the system conditions during just a single hour of the day would be used to compute the index. For this study, the daily LOLE was based on all of the hours in the day. If the system were short of capacity at any time during the day, whether it was a peak or off-peak hour, it would be counted as a day of outage. If the system were short for several hours during the day, it would still count as a single day of outage.

MARS uses a sequential Monte Carlo simulation to calculate the reliability of a generation system that is made up of a number of interconnected areas. The areas are defined based on the limiting interfaces within the transmission system. Generating units and an hourly load profile are assigned to each area. MARS performs a chronological hourly simulation of the system, comparing the hourly load in each area to the total available generation in the area, which has been adjusted for planned maintenance and randomly occurring forced outages.

If an area's available generation is less than its load, the program will attempt to deliver assistance from areas that have a surplus that hour, subject to the transfer limits between the areas. If the assistance is not available or it cannot be delivered to the deficient area, the area will be considered to be in a loss-of-load state for that hour, and the statistics required to compute the reliability indices will be collected. This process is repeated for all of the hours in the year. The year is then simulated with different random forced outages on the generating units and transmission interfaces until the simulation has converged. For this study, each study year was simulated 1,000 times.

The reliability calculations in MARS are done at the area level – the generating units are assigned to areas, the hourly load profiles are defined by area, and the interface transfer limits are modeled between areas. The pool indices in MARS are computed from the area results: if one or more of the areas in a given pool are deficient in an hour, then the pool is considered as being deficient. In this study, CAISO was modeled as three interconnected areas, so if at least one of the CAISO areas were deficient in an hour, then CAISO was counted as being deficient.

A detailed description of the MARS program can be found in Appendix A.

RESERVE MARGIN CALCULATION

As was discussed in the Final Report for the 2008 study, there are several ways in which the reserve margin can be calculated. The basis calculation is the same:

Reserve Margin = (Available Capacity / Peak Load) –1

The difference comes when applying this concept across the year. The three basic variations considered in the 2008 study were:

1. **Annual Reserves**. The reserve margin is measured at the time of the annual peak load and this total capacity is maintained throughout the year.
2. **Monthly Reserves**. The reserve margin is measured at the time of each monthly peak. The capacity required to maintain a specified percent reserve margin will vary each month.
3. **Constant MW Reserves**. The reserve margin is determined at the time of the annual peak load and that amount of MW of reserve is maintained each month. The capacity required each month will vary but the "cushion" between the available capacity and the monthly peak will remain constant.

In the 2008 study, the monthly reserves was the primary method used, although a number of sensitivities were run using the other method. **All of the simulations in the current study were based on the annual reserves calculated using the coincident peak loads of the areas.** The use of the annual reserves is a significant change that should be noted when comparing results between studies. In the 2008 study, the difference in the reserve requirements between annual and monthly was estimated at 4.2%, with the monthly reserve requirement being higher.

Resources Included "In the Margin"

Also related to the calculation of reserve margins is the question as to what resources should be included "in the margin". The reserve margin typically includes all of the generating resources that provide reliability service to the system and can be used to mitigate outage events. The inclusion of other types of resources such as imports and demand response varies between system operators.

The treatment of imports is a particularly important issue. Neighboring systems can be an important source of firm capacity. They can "bid in" to provide resources to meet reserve requirements just as the local generation can. As long as there is sufficient transmission, this will provide a broader market for capacity and should help to hold prices down. But in addition to the firm resources that neighboring systems can provide, there are also "emergency resources" available. When outages occur and available reserves start dropping, the system marginal costs will rise. At these times in particular, neighboring systems are generally more than willing to sell any available resources even if no capacity agreements are in place. These energy purchases can help the system to avoid outages, but do not count towards the reserve margin. In fact, they help reduce the overall reserve margin that needs to be maintained.

For the 2008 study, the initial Base Case assumption was that imports and demand response were not included in the reserve margin or reliability calculations. Rather, these resources could be used to satisfy a portion of the PRM requirements, thus reducing the reserves that must be met with other sources of generation. The Revised Base Case in that study included in the reserve margin calculations the demand response and the imports associated with the out-of-state generation. It also included additional imports in only the reliability calculations. The approach of the Revised Base Case was used in the current study.

Summarizing, **for this study the reserve margins were calculated on an annual basis and included the demand response and the imports associated with the out-of-state generation.** Additional imports were included in the reliability calculations although they were not included in the reserve margins.

3 Data Assumptions

For the 2008 study, a MARS Base Case was developed from data primarily provided by CAISO staff, with assistance from the IOUs and the State agencies. This database was then updated and modified for use in the current study. This section describes the data required by MARS, the sources of the data used in this study, and any assumptions that were made relative to the data.

UNIT DATA

The generating unit data for the CAISO system was developed from data submitted by the CAISO staff. The data provided for each thermal unit included:

- Name
- Area location
- Unit type
- Installation and retirement dates (all units assumed to retire after the study period)
- Planned outage rate
- Forced outage rate (EFORd) and number of forced outages per year
- Monthly unit capacities in MW

The forced outage data was taken from the NERC GADS 2002-2006 Generating Unit Statistical Brochure – All Units Reporting by unit type and size. MARS uses state transition rates, rather than forced outage rates, in its reliability calculations. The program can calculate the state transition rate from the forced outage rate and the number of forced outages per year.

For the hydro units, the same data was provided as for the thermal units with the exception of the forced outage rates that are not modeled for hydro units in MARS. Additionally, the amount of energy available from each unit each month was specified based on average monthly output using CEC/EIA 906 data from 1994-2005. MARS also allows input of a minimum rating which was assumed to be 10% of the maximum rating based on data from historical FERC Form 12 filings for California utilities. For about twenty units with insufficient monthly energy to support a minimum rating equal to 10% of the maximum, the minimum was set to 0 MW.

Wind, solar, biomass, geothermal, and small hydro were modeled in the Base Case with hourly profiles for all of the hours in the year based on actual operation for 2007, and scaled as needed for expected penetration levels and operation in 2010.

Table 1 through Table 4 on the following pages show the installed capacity and peak load that are projected for 2010, along with the reserve margin by month, for each of the three areas and for CAISO. The reserve margins shown include all of the resources listed except for the imports.

The monthly values reflect any seasonal variations in unit output being modeled along with mid-year unit installations. For hourly resources such as wind and solar, the capacity shown is the maximum of the hourly values for the month.

Demand response was modeled as energy limited units with a maximum rating and monthly or annual available energy calculated from the number of hours per month or year that the action can be implemented.

The out-of-state generation was not modeled as actual generating units but rather as a fixed MW value for all of the hours in the year. The out-of-state generation was included in both the reserve margin and reliability calculations, while the other imports were included in only the reliability calculations.

The load and capacity at the time of the annual peak is shown in Table 5 for the three areas and CAISO for each of the study years. Also shown is the reserve margin for the "as-found" system calculated on the basis of the coincident and non-coincident area peak loads. As shown in the table, the reserve margins vary significantly between the areas. For CAISO, the reserve margins start at 31.4% in 2010 and decline to 17.6% by 2020.

Table 1 - "As Found" Installed Capacity and Peak Load for Northern California Area (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00
Fossil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fossil-Gas	2,691.94	2,691.94	2,686.93	2,681.93	2,676.93	2,671.93	2,666.93	2,666.93	2,671.93	2,676.93	2,686.93	2,691.94
GT-Oil	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00
GT-Gas	5,730.57	5,730.57	5,723.27	5,721.27	5,719.27	5,717.27	5,717.27	5,717.27	5,718.27	5,724.27	5,730.57	5,730.57
C.C.	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	2,459.40	2,459.40	2,459.40
I.C.	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72
Diesel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ST-Gas	5,789.90	5,789.90	5,789.90	5,789.90	5,789.90	5,789.90	5,789.90	5,789.90	5,789.90	5,789.90	5,789.90	5,789.90
ST-Other	1,395.65	1,395.65	1,395.65	1,395.65	1,395.65	1,395.65	1,382.65	1,382.65	1,382.65	1,395.65	1,395.65	1,395.65
ST-Coal	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70
Other	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34
Refuse	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93
Hydro	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44
Hydro-RR	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99
Hydro-Small	88.60	106.60	107.70	87.70	107.30	62.30	65.90	50.80	36.80	35.20	38.70	50.00
Non-RPS	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00
Biomass	401.20	377.60	364.10	347.40	370.00	443.50	438.70	434.20	432.80	400.40	391.80	377.60
Geothemal	124.20	124.00	124.50	130.90	127.40	125.30	124.50	125.80	126.00	123.90	122.70	123.50
Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	198.12	171.63	378.93	372.85	413.34	388.72	386.22	392.60	371.67	322.63	98.08	59.05
Cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response	0.00	0.00	0.00	0.00	830.15	1,063.80	1,069.70	1,074.03	1,070.49	836.44	0.00	0.00
Out-of-State Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Imports	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00
TOTAL	**31,732.70**	**31,700.41**	**31,883.50**	**31,840.12**	**32,742.46**	**32,970.89**	**32,954.29**	**32,946.70**	**32,913.03**	**33,277.84**	**32,226.85**	**32,190.73**
Non-Coincident Peak	15,525.10	14,869.50	14,430.40	14,722.40	18,600.90	20,230.70	**22,076.00**	20,880.20	19,462.80	16,153.10	15,005.30	15,645.60
Reserve Margin (%)	97.95	106.47	114.02	109.48	70.65	58.03	44.75	53.00	63.97	99.82	108.11	99.36

Table 2 - "As Found" Installed Capacity and Peak Load for Southern California Area (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear	2,254.00	2,254.00	2,254.00	2,254.00	2,254.00	2,254.00	2,254.00	2,254.00	2,254.00	2,254.00	2,254.00	2,254.00
Fossil	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Fossil-Gas	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22
GT-Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GT-Gas	4,796.52	4,796.52	4,796.52	4,796.52	4,796.52	4,796.52	4,796.52	5,146.52	5,146.52	5,146.52	5,146.52	5,146.52
C.C.	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91
I.C.	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30
Diesel	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00
Steam	581.91	604.27	662.61	721.09	771.86	861.34	862.54	862.58	867.46	671.58	599.02	566.20
ST-Gas	8,592.26	8,592.26	8,592.26	8,592.26	8,592.26	8,592.26	8,592.26	8,777.26	8,777.26	8,777.26	8,777.26	8,777.26
ST-Other	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26
ST-Coal	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00
Other	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41
Refuse	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20
Hydro	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99
Hydro-RR	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23
Hydro-Small	73.02	52.53	58.30	83.98	102.16	101.20	55.89	47.04	42.52	20.88	13.08	9.62
Non-RPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	196.87	195.89	193.46	193.21	189.07	192.85	194.55	195.04	193.21	193.33	193.21	193.09
Geothemal	983.58	974.48	964.30	981.63	970.80	1,004.05	979.03	984.34	986.61	996.14	982.61	1,013.15
Solar	129.16	210.99	274.95	302.86	329.82	377.62	370.07	366.82	367.87	234.51	181.16	329.15
Wind	859.49	888.38	888.38	884.69	862.06	847.62	841.79	804.50	883.46	912.69	890.29	810.21
Cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response	0.00	0.00	0.00	0.00	1,035.61	1,587.16	1,701.83	1,531.84	1,614.52	996.37	0.00	0.00
Out-of-State Generation	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00
Imports	4,712.00	4,712.00	4,712.00	4,712.00	4,712.00	4,712.00	4,712.00	4,712.00	4,712.00	4,712.00	4,712.00	4,712.00
TOTAL	**29,290.49**	**29,393.00**	**29,508.46**	**29,633.92**	**30,727.84**	**31,438.30**	**31,472.16**	**31,793.62**	**31,957.11**	**31,026.96**	**29,860.83**	**29,922.88**
Non-Coincident Peak	14,994.50	14,428.80	14,467.70	15,896.60	18,489.40	20,617.90	22,549.00	**23,891.90**	22,228.80	17,781.60	15,120.30	15,505.90
Reserve Margin (%)	63.92	71.05	71.39	56.78	40.71	29.63	18.68	13.35	22.57	47.99	66.32	62.59

Table 3 - "As Found" Installed Capacity and Peak Load for San Diego Area (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fossil	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Fossil-Gas	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88
GT-Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GT-Gas	2,120.05	2,120.05	2,120.05	2,120.05	2,120.05	2,120.05	2,120.05	2,120.05	2,120.05	2,120.05	2,120.05	2,120.05
C.C.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I.C.	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10
Diesel	22.75	22.75	22.75	22.75	22.75	22.75	22.75	22.75	22.75	22.75	22.75	22.75
Steam	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ST-Gas	1,267.90	1,267.90	1,267.90	1,267.90	1,267.90	1,267.90	1,267.90	1,267.90	1,267.90	1,267.90	1,267.90	1,267.90
ST-Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ST-Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refuse	14.42	14.42	14.42	14.42	14.42	14.42	14.42	14.42	14.42	14.42	14.42	14.42
Hydro	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59
Hydro-RR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro-Small	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-RPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	68.80	65.00	64.70	65.20	41.40	67.70	69.50	65.10	75.40	133.40	126.90	47.00
Geothemal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cogen	172.40	174.50	168.60	170.30	176.20	169.20	171.20	169.80	170.40	167.90	168.30	167.00
Demand Response	81.30	81.30	81.30	81.30	235.60	235.60	235.60	235.60	235.60	126.70	81.30	81.30
Out-of-State Generation	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00
Imports	1,598.00	1,598.00	1,598.00	1,598.00	1,598.00	1,598.00	1,598.00	1,598.00	1,598.00	1,598.00	1,598.00	1,598.00
TOTAL	**6,127.19**	**6,125.49**	**6,119.29**	**6,121.49**	**6,257.89**	**6,277.19**	**6,280.99**	**6,275.19**	**6,286.09**	**6,232.69**	**6,181.19**	**6,099.99**
Non-Coincident Peak	3,281.60	3,212.00	3,068.80	3,288.60	3,485.50	3,807.70	4,198.50	**4,595.30**	4,239.30	3,661.50	3,309.50	3,430.80
Reserve Margin (%)	38.02	40.96	47.33	37.55	33.69	22.89	11.54	1.78	10.59	26.58	38.49	31.22

Table 4 - "As Found" Installed Capacity and Peak Load for CAISO System (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear	4,554.00	4,554.00	4,554.00	4,554.00	4,554.00	4,554.00	4,554.00	4,554.00	4,554.00	4,554.00	4,554.00	4,554.00
Fossil	50.16	50.16	50.16	50.16	50.16	50.16	50.16	50.16	50.16	50.16	50.16	50.16
Fossil-Gas	3,184.04	3,184.04	3,179.03	3,174.03	3,169.03	3,164.03	3,159.03	3,159.03	3,164.03	3,169.03	3,179.03	3,184.04
GT-Oil	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00
GT-Gas	12,647.14	12,647.14	12,639.84	12,637.84	12,635.84	12,633.84	12,633.84	12,983.84	12,984.84	12,990.84	12,997.14	12,997.14
C.C.	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,900.31	3,900.31	3,900.31
I.C.	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12
Diesel	50.75	50.75	50.75	50.75	50.75	50.75	50.75	50.75	50.75	50.75	50.75	50.75
Steam	581.91	604.27	662.61	721.09	771.86	861.34	862.54	862.58	867.46	671.58	599.02	566.20
ST-Gas	15,650.06	15,650.06	15,650.06	15,650.06	15,650.06	15,650.06	15,650.06	15,835.06	15,835.06	15,835.06	15,835.06	15,835.06
ST-Other	1,879.91	1,879.91	1,879.91	1,879.91	1,879.91	1,879.91	1,866.91	1,866.91	1,866.91	1,879.91	1,879.91	1,879.91
ST-Coal	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70
Other	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75
Refuse	877.55	877.55	877.55	877.55	877.55	877.55	877.55	877.55	877.55	877.55	877.55	877.55
Hydro	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02
Hydro-RR	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22
Hydro-Small	161.62	159.13	166.00	171.68	209.46	163.50	121.79	97.84	79.32	56.08	51.78	59.62
Non-RPS	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00
Biomass	666.87	638.49	622.26	605.81	600.47	704.05	702.75	694.34	701.41	727.13	711.91	617.69
Geothemal	1,107.78	1,098.48	1,088.80	1,112.53	1,098.20	1,129.35	1,103.53	1,110.14	1,112.61	1,120.04	1,105.31	1,136.65
Solar	129.16	210.99	274.95	302.86	329.82	377.62	370.07	366.82	367.87	234.51	181.16	329.15
Wind	1,057.61	1,060.01	1,267.31	1,257.54	1,275.40	1,236.34	1,228.01	1,197.10	1,255.13	1,235.32	988.37	869.26
Cogen	172.40	174.50	168.60	170.30	176.20	169.20	171.20	169.80	170.40	167.90	168.30	167.00
Demand Response	81.30	81.30	81.30	81.30	2,101.36	2,886.56	3,007.13	2,841.47	2,920.61	1,959.51	81.30	81.30
Out-of-State Generation	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00
Other Imports	7,310.00	7,310.00	7,310.00	7,310.00	7,310.00	7,310.00	7,310.00	7,310.00	7,310.00	7,310.00	7,310.00	7,310.00
TOTAL	**67,150.38**	**67,218.90**	**67,511.25**	**67,595.53**	**69,728.19**	**70,686.38**	**70,707.44**	**71,015.51**	**71,156.23**	**70,537.49**	**68,268.87**	**68,213.60**
Non-Coincident Peak	33,611.20	32,321.20	31,600.10	33,509.70	39,909.00	43,655.40	47,712.60	**48,496.80**	43,873.50	36,806.50	33,425.90	34,261.40
Reserve Margin (%)	78.04	85.35	90.51	79.90	56.40	45.17	32.87	31.36	45.52	71.78	82.37	77.76

Table 5 - Load and Capacity at Time of Annual Peak (MW)

2010

	No.Cal.	So.Cal.	San Diego	CAISO
Capacity	30,884.59	24,061.78	3,739.59	58,674.04
Demand Response	1,069.70	1,531.84	235.60	2,841.47
Out-of-State Generation	0.00	1,488.00	702.00	2,190.00
Peak				
Coincident	20,747.63	23,284.64	4,465.15	48,497.42
Non-Coincident	22,076.00	23,891.90	4,595.30	48,496.80
Res. Margin (%)				
Coincident Peak	54.01	16.31	4.75	31.36
Non-Coincident Peak	44.75	13.35	1.78	31.36

2015

	No.Cal.	So.Cal.	San Diego	CAISO
Capacity	31,534.57	24,741.68	3,739.59	60,015.84
Demand Response	1,074.03	1,531.84	235.60	2,841.47
Out-of-State Generation	0.00	1,488.00	702.00	2,190.00
Peak				
Coincident	22,172.85	24,939.92	4,800.95	51,913.71
Non-Coincident	23,592.50	25,590.40	4,940.80	51,913.10
Res. Margin (%)				
Coincident Peak	47.07	11.31	-2.58	25.30
Non-Coincident Peak	38.22	8.48	-5.34	25.30

2020

	No.Cal.	So.Cal.	San Diego	CAISO
Capacity	31,534.57	24,741.68	3,739.59	60,015.84
Demand Response	1,074.03	1,531.84	235.60	2,841.47
Out-of-State Generation	0.00	1,488.00	702.00	2,190.00
Peak				
Coincident	23,549.30	26,650.79	5,098.77	55,298.85
Non-Coincident	25,057.10	27,345.90	5,247.30	55,298.20
Res. Margin (%)				
Coincident Peak	38.47	4.17	-8.27	17.63
Non-Coincident Peak	30.14	1.52	-10.86	17.63

Outage Rates

Table 6 shows the MW-weighted average planned and forced outage rates (EFORd) by area and unit type for the thermal units.

Table 6 - MW-Weighted Average Outage Rates (%)

	No. Cal.		So. Cal.		San Diego		CAISO	
	P.O.R.	**F.O.R.**	**P.O.R.**	**F.O.R.**	**P.O.R.**	**F.O.R.**	**P.O.R.**	**F.O.R.**
Nuclear	4.25	2.87	6.66	2.87			5.44	2.87
Fossil			0.00	7.95	4.72	7.95	4.70	7.95
Fossil-G	3.25	8.46	2.93	8.64	2.92	8.39	3.20	8.49
GT-Oil	1.09	10.30					1.09	10.30
GT-Gas	2.55	8.69	2.43	8.53	3.70	10.10	2.68	8.85
C.C.	4.89	6.33	4.89	6.33			4.89	6.33
I.C.	2.70	16.70	3.04	8.39	3.07	8.39	2.72	16.13
Diesel			1.09	10.30	1.09	10.30	1.09	10.30
Steam			4.07	6.90			4.07	6.90
ST-Gas	8.14	7.23	7.75	6.93	7.22	6.80	7.85	7.03
ST-Other	2.21	3.36	3.12	5.49			2.45	3.91
ST-Coal	5.39	6.96	5.39	6.96			5.39	6.96
Other	4.72	7.95	4.51	7.55			4.52	7.58
Refuse	4.55	8.08	3.36	11.95	2.33	22.73	4.16	9.48

As a way of reviewing the forced outage rate data, Figure 1 plots the unit forced outage rates (EFORd) as a function of the unit size for the 762 thermal units being modeled. As would be expected when using class-average data rather than unit-specific data, there is significant clustering of the data, but the plot does show the range of values being assumed. There are a number of units with very high and very low forced outage rates, but for the most part these units are fairly small. The vast majority of the units have forced outage rates in the 6% to 8% range.

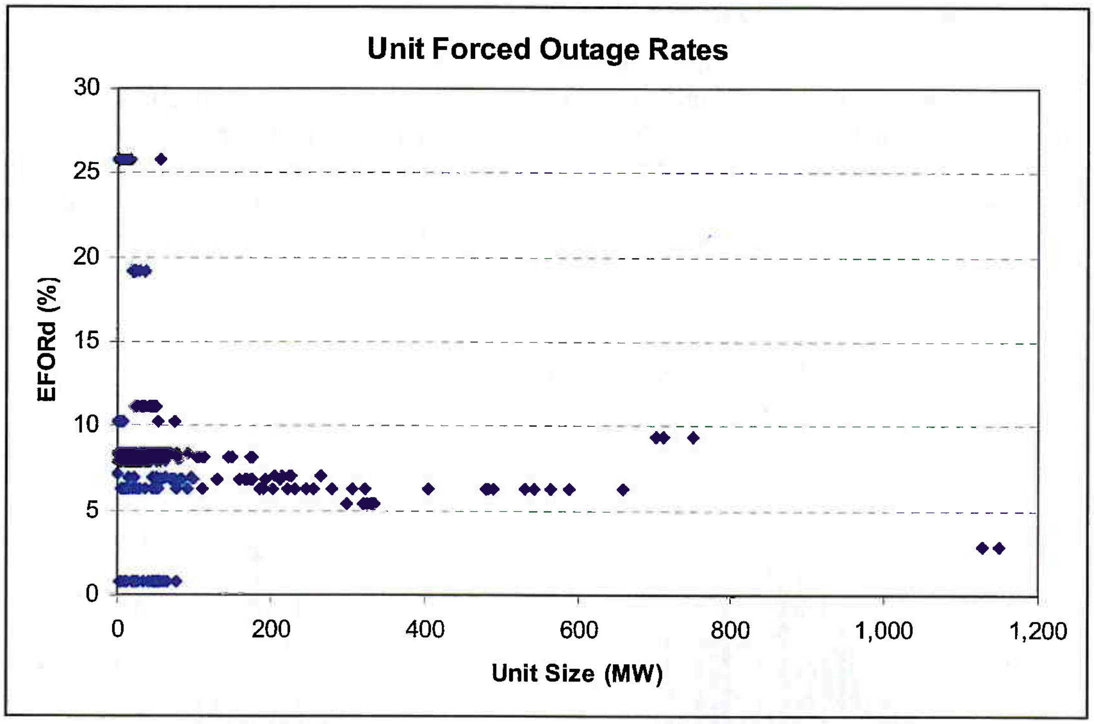


Figure 1 - Unit Forced Outage Rates versus Size

Hydro Capacity Factors

Figure 2 shows the range of monthly capacity factors for the hydro units modeled. Most of the units fall within the expect range of 20% to 80% while there are some outliers.

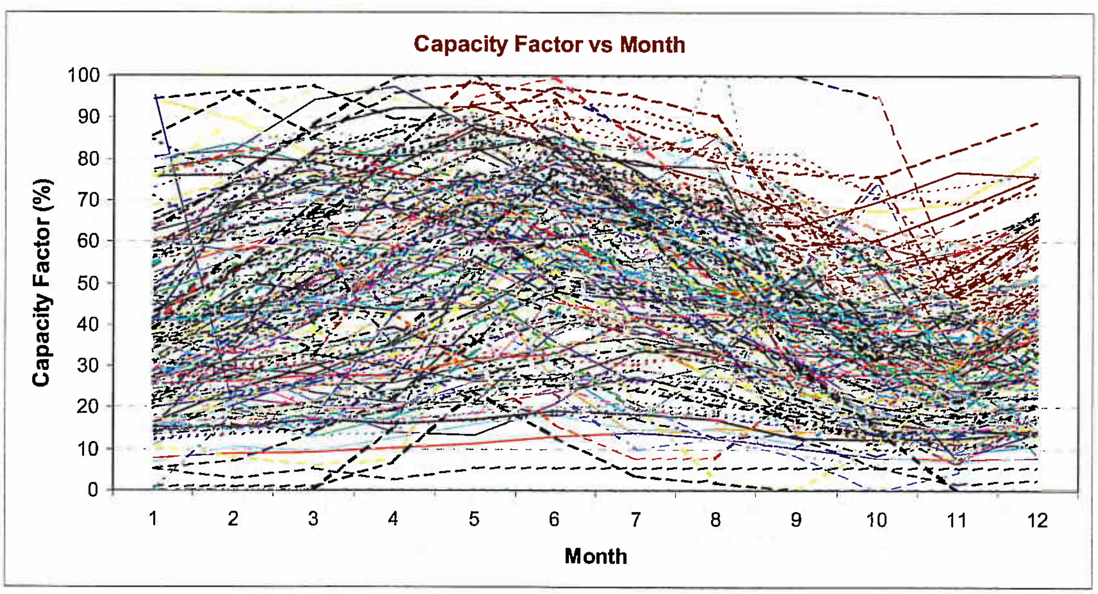


Figure 2 - Hydro Unit Monthly Capacity Factors

Planned Maintenance Schedule

For these cases, the planned maintenance was scheduled by the program for all units except one nuclear unit for which its maintenance schedule had been specified for 2010. The program scheduled the maintenance on an area basis so as to levelize, as much as possible given the discrete sizes of the units, the weekly MW margins, calculated as the installed capacity minus the peak load minus the capacity on maintenance. The total capacity on scheduled maintenance each week for the CAISO system for 2010, along with the remaining margins, are shown in Figure 3.

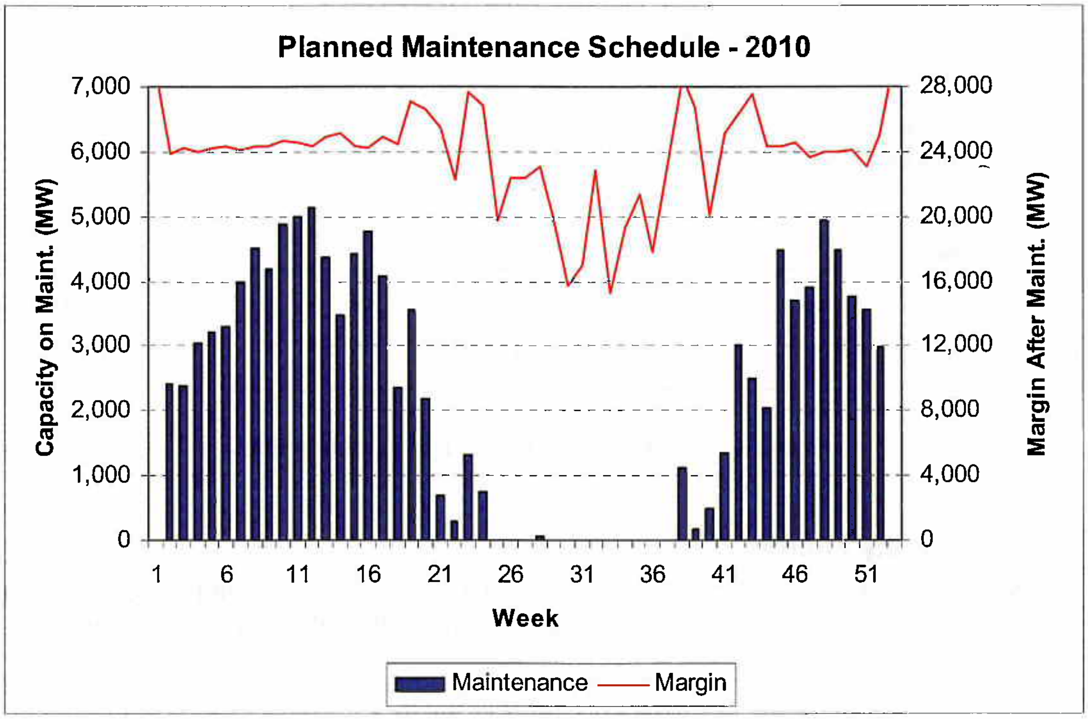


Figure 3 - CAISO Capacity on Scheduled Maintenance - 2010

The maintenance schedule for the CAISO generating units developed by the program resulted in weekly margins that were fairly constant at approximately 22,000 MW except during the peak weeks when, even with no maintenance scheduled, the margins dropped to a low of about 13,000 MW.

INTERFACE TRANSFER LIMITS

The CAISO system was modeled as three interconnected areas. The interface between the Northern California and Southern California areas had a rating of 3,750 MW from north to south, and a rating of 2,902 MW going from south to north. The rating of the interface between Southern California and San Diego was modeled as a function of the availability of the two SONGS units. This relationship is shown in Table 7.

Table 7 - Southern California to San Diego Interface Rating

Status of SONGS Units		Interface Flow Limit (MW)	
Unit 1	**Unit 2**	**North - South**	**South - North**
Available	Available	2,200	236
Unavailable	Available	2,200	1,314
Available	Unavailable	2,200	1,316
Unavailable	Unavailable	2,200	2,440

LOADS

Load Shape

MARS requires a chronological hourly load shape for each area being modeled. This data is often developed from historical hourly load data from a year with weather, economic, and other characteristics similar to the year to be studied. In other words, the hourly shape from a year with "normal" weather conditions would typically be used as a base case load model, while a shape from a year with "extreme" weather conditions may be used for a sensitivity case.

The historical hourly load profile for the CAISO areas for the year 2007 was selected as being representative of a year with normal hot summer weather, and was used in developing the Base Case load model. The 2007 shapes were adjusted by CEC to match the peak load projections for 2010, 2015, and 2020.

Load Forecast Uncertainty

To model the uncertainty associated with the peak load projections through time, MARS computes the reliability indices at multiple levels of assumed monthly peak loads. In this process, all of the hourly loads in the month are adjusted by the same percentage as the monthly peak load. MARS then calculates a weighted-average value for each index based on the probabilities corresponding to the load levels.

For this study, hourly load profiles for the 1-in-2, 1-in-5, 1-in-10, and 1-in-20 load forecasts were provided. The load forecast uncertainty, as a per unit of the monthly peak of the 1-in-2 forecast, is shown for the three areas in Figure 4 through Figure 6. For Northern California, the same uncertainty was used for all three study years. For the other two areas, the same uncertainty was assumed for 2015 and 2020, which differed only slightly from that for 2010. In all cases, the uncertainty increases during the months immediately before and after the peak summer season.

The probabilities associated with the 1-in-2, 1-in-5, 1-in-10, and 1-in-20 load forecasts were 50%, 30%, 10%, and 10%, respectively.

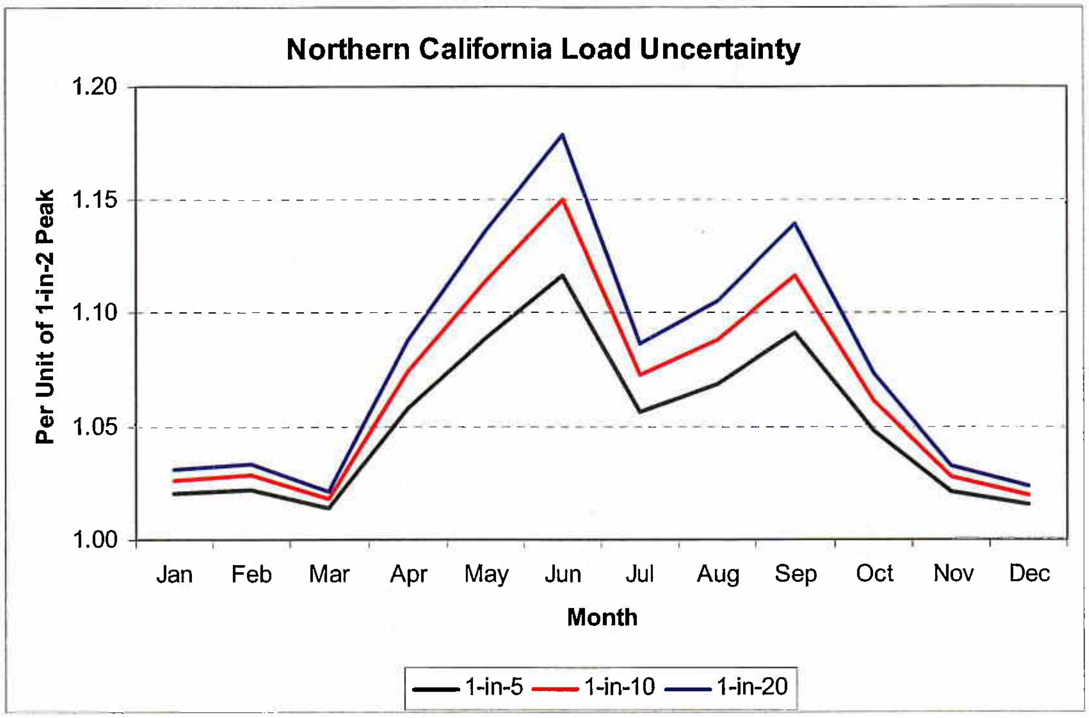


Figure 4 - Northern California Load Uncertainty

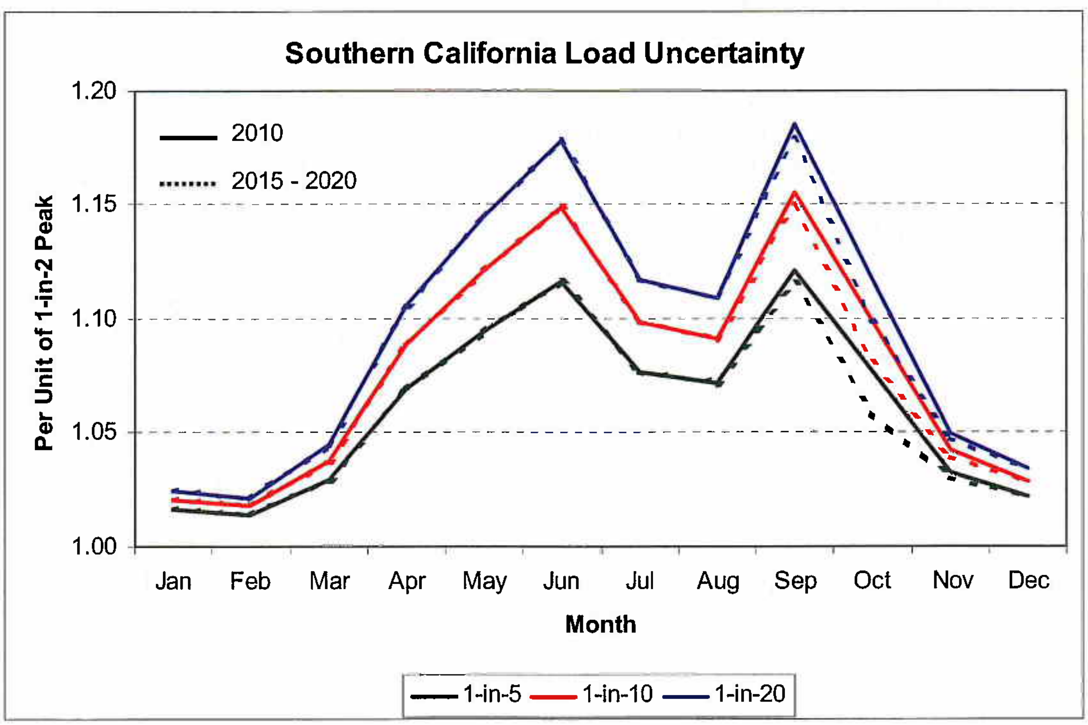


Figure 5 - Southern California Load Uncertainty

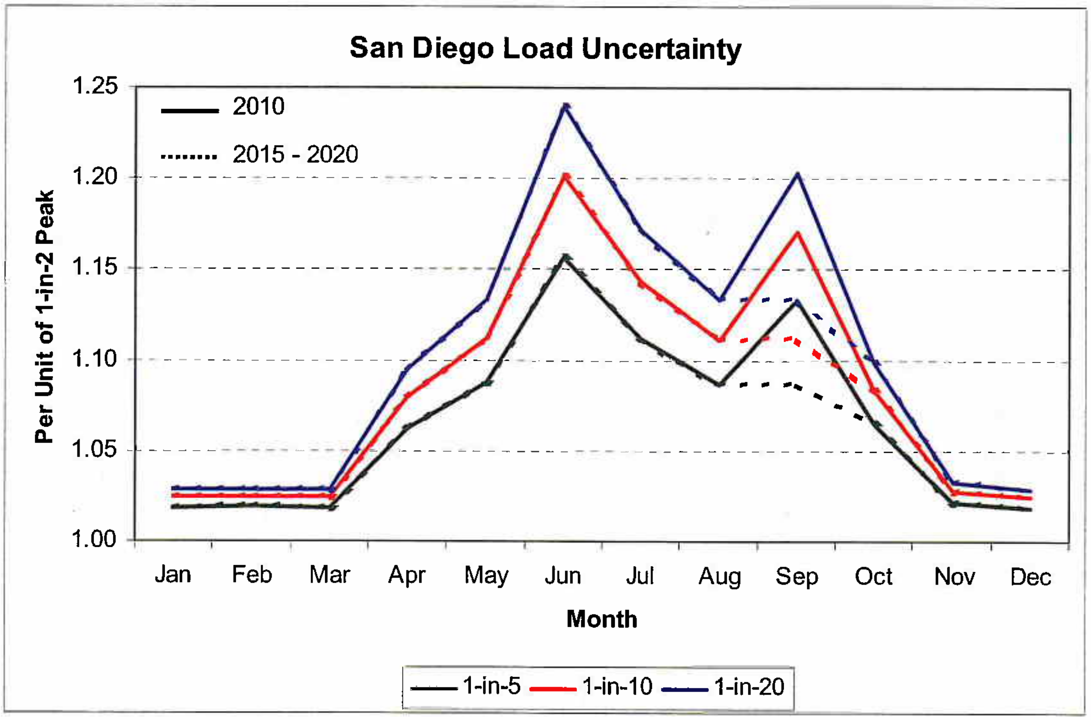


Figure 6 - San Diego Load Uncertainty

4 Results

The PRM was determined for a number of different scenarios for the study years of 2010, 2015, and 2020. These results are summarized in Table 8 and are discussed in detail in the sections that follow.

Table 8 - Summary of Study Results

	Annual PRM (%)		
Case	**2010**	**2015**	**2020**
Base Case with Load Forecast Uncertainty	8.1	8.5	8.7
Base Case 1-in-2	0.8	1.0	1.2
Base Case 1-in-5	6.7	7.1	7.0
Base Case 1-in-10	8.7	8.9	9.1
Base Case 1-in-20	10.4	10.7	10.8
Base Case with 4 Load Models	7.6	8.0	8.1
Extreme Load	10.4	10.7	10.8
Extreme Hydro	8.1	8.5	8.7
Extreme Load and Hydro	10.4	10.8	10.8
Extreme Hydro without Carryforward	9.2	9.4	9.4
25% Increase in EFORs	10.3		
OTC Retirements		8.3	6.7
Renewables			27.2

IMPACT OF CHANGED LOAD DATA

The Revised Base Case with annual reserve margins from the 2008 study was the starting point for this study. Among the other key assumptions in that simulation were monthly scalars for modeling load forecast uncertainty, the option to carry unused hydro energy from one month to the next, and including demand response and out-of-state generation in both the reserve margin and reliability calculations. It also included 7,310 MW[7] of non-firm emergency assistance from outside areas in the reliability, but not the reserve margin, calculations. The PRM for 2010 in that case in the 2008 study was 9.2%.

To facilitate the comparison with the results from the previous study, the changes to the load model were first introduced to the data for this study, while leaving the generating unit data unchanged. Figure 7 shows the CAISO risk as a function of reserve margins as the new load data, provided by the California Energy Commission (CEC), is introduced into the study.

[7] These imports are in addition to the out-of-state generation (2,190 MW) that are included in the reserve margin calculations. The total imports modeled for reliability was 9,500 MW.

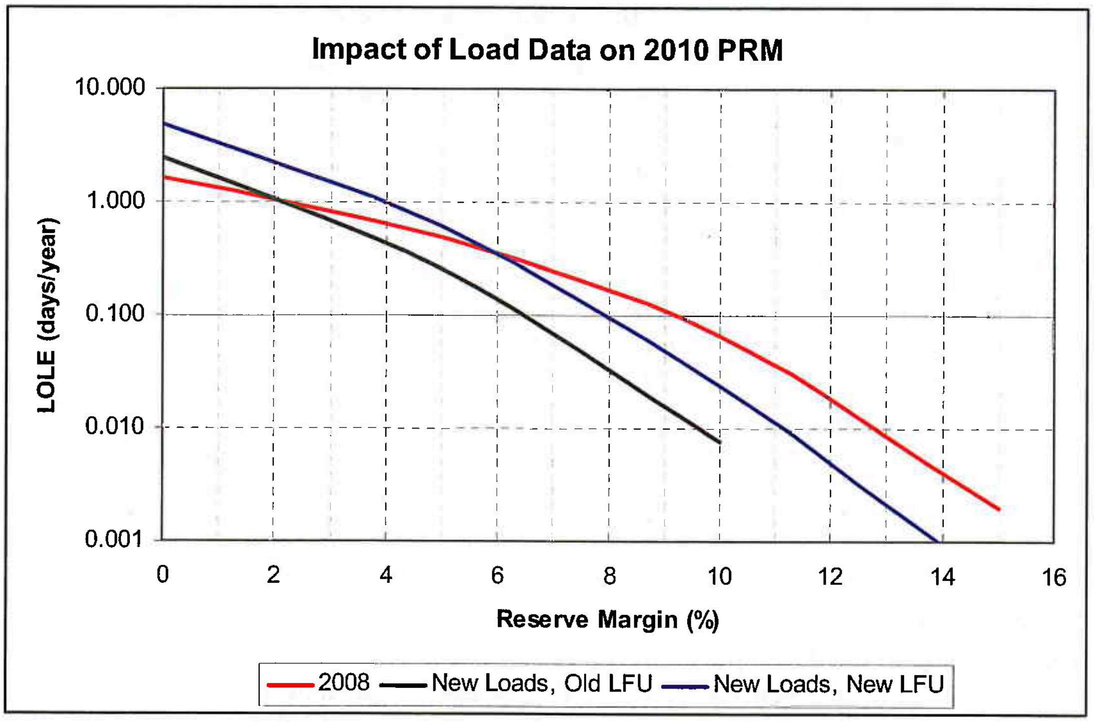


Figure 7 - Impact of Load Data on 2010 PRM

When the new hourly load profiles and peaks, provided by the CEC, were used with the load forecast uncertainty multipliers from the 2008 study, the PRM dropped from 9.2% in the 2008 study (red curve) to 6.5% (green curve). In the 2008 study, all three areas peaked in September. In the hourly load data being used for the current study, Northern California peaked in July and the other two areas peaked in August. As a result of the increased load diversity between the areas, they were able to provide more assistance to one another, which allowed the same level of reliability to be maintained with slightly lower reserves.

When the new load forecast uncertainty scalars, derived from the hourly load data provided by the CEC, shown in Figure 4 to Figure 6 were introduced into the data, the PRM increased from 6.5% to 8.0% (blue curve). A comparison of the load uncertainty data for the 2008 and current studies for the peak months of July and August (Table 9) shows, in most instances, a greater amount of uncertainty in the current study data, resulting in the need for a higher PRM.

Table 9 - Load Forecast Uncertainty (% Increase Over 1-in-2 Load)

	July		August	
	2008	Current	2008	Current
No. Cal.				
1-in-5	4.65	5.65	2.64	6.89
1-in-10	6.05	7.25	3.67	8.84
1-in-20	7.89	8.64	7.76	10.53
So. Cal.				
1-in-5	5.45	7.64	6.63	7.12
1-in-10	9.10	9.80	7.73	9.14
1-in-20	11.70	11.68	10.69	10.88
San Diego				
1-in-5	6.90	11.20	6.80	8.68
1-in-10	10.60	14.38	8.80	11.12
1-in-20	13.70	17.13	14.90	13.27

BASE CASE

The final step in the development of the Base Case from the 2008 study database was to update the data for the generating units. The changes to the unit data consisted primarily of minor changes to unit ratings and to the planned and forced outage rates of some of the units. The total installed capacity of CAISO was reduced by 418 MW.

The CAISO LOLE as a function of reserve margin for the three study years is shown in Figure 8. For 2010, the changes to the generating data increased the PRM from 8.0% to 8.1%. The PRM increased slightly to 8.5% in 2015 and 8.7% in 2020.

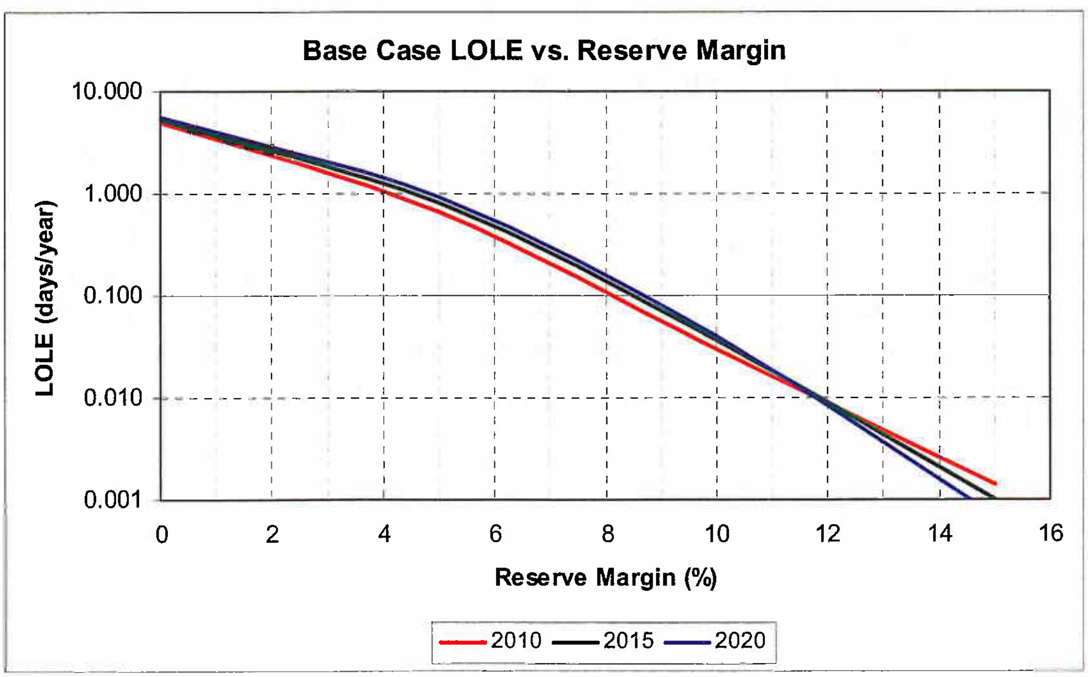


Figure 8 - Base Case LOLE versus Reserve Margin

MODELING OF LOAD FORECAST UNCERTAINTY

During the 2008 study, there was some discussion as to whether the way in which MARS handles load forecast uncertainty may have been too extreme. In MARS, this is done by inputting a 1-in-2 load shape and peak load forecast along with monthly per unit multipliers to model the load forecast uncertainty. The load forecast multipliers are applied to each hour of the month. For each hour of the simulation, the program calculates the risk at each of the load levels. At the end of the simulation, it combines the results for each load level using the corresponding probabilities to calculate an expected value of the LOLE for the year.

The concern was that applying the multipliers to all hours of the month, rather than just the few hours during which the load would most likely be increasing in response to the weather, was too extreme. This would be especially true with a large amount of energy-limited capacity.

To assess the impact on PRM of applying the same multipliers to all hours, separate 1-in-2, 1-in-5, 1-in-10, and 1-in-20 load models were provided for the areas for each study year. This data was used to calculate the ratios of the monthly peaks in the 1-in-5, 1-in-10, and 1-in-20 loads relative to the 1-in-2 monthly peaks shown in Figure 4 to Figure 6. These values were used for the load forecast uncertainty scalars in the Base Case simulations.

Additional simulations were then run for each of the four load shapes, without using the load forecast uncertainty multipliers. The reliability results for the four load models were then combined using the associated probabilities to calculate with expected values of LOLE for a range of reserve margins. The results of these simulations are shown in Figure 9 through Figure 11.

For 2010, as shown in Figure 9, the PRM for the individual load shapes ranged from approximately 0.75% for the 1-in-2 shape to more than 10% for the 1-in-20 shape. Combining the results of the four simulations using their associated probabilities produces the light blue curve, which indicates a PRM of approximately 7.6%. The results for the Base Case using the load forecast uncertainty multipliers, which indicate a PRM of 8.1%, are shown by the black curve. The results for 2015 and 2020 are similar to those for 2010: 8.0% compared to 8.5% in 2015, and 8.1% compared to 8.7% in 2020.

The higher PRM when using the load forecast uncertainty multipliers is to be expected since this method assumes that loads for all of the hours in the month are increased, rather than just a limited number of hours. However, the amount of the increase indicates that this method does not excessively increase the risk or PRM. This method also allows for a single MARS simulation rather than separate simulations for each load level.

The load forecast uncertainty multipliers, rather than the individual load forecast shapes, were used for the remaining simulations in this study.

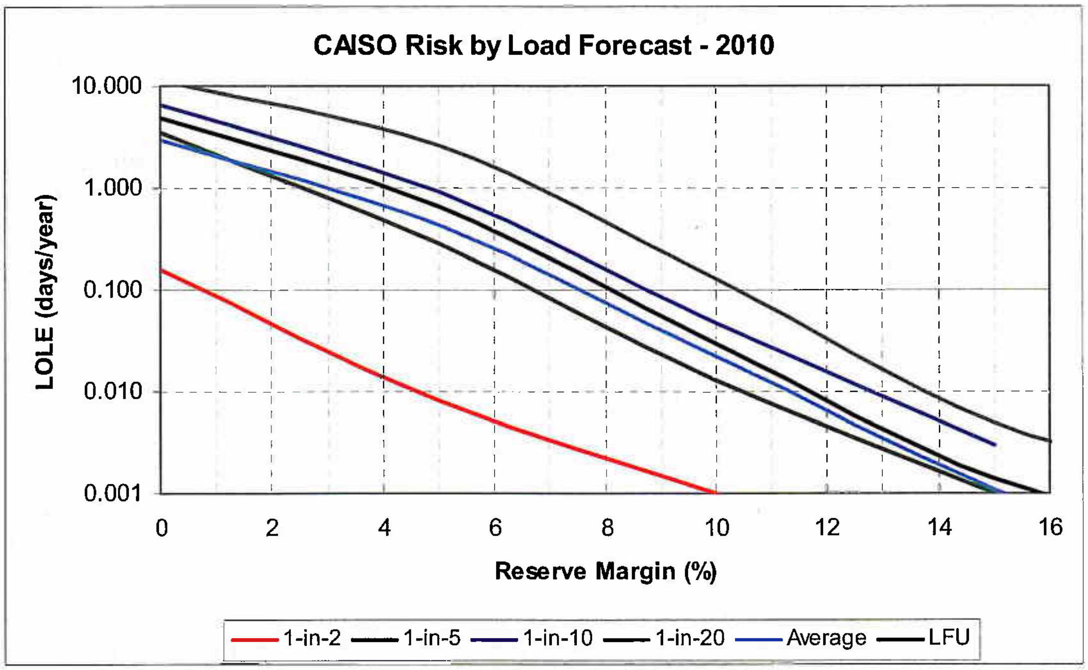


Figure 9 - CAISO Risk by Load Forecast – 2010

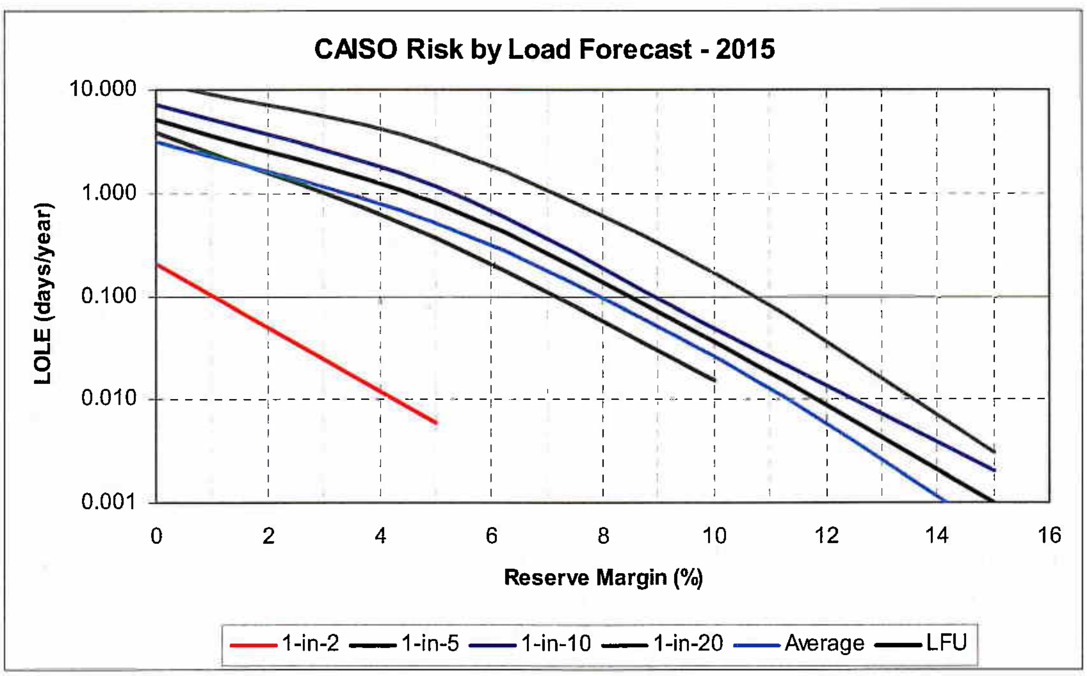


Figure 10 - CAISO Risk by Load Forecast – 2015

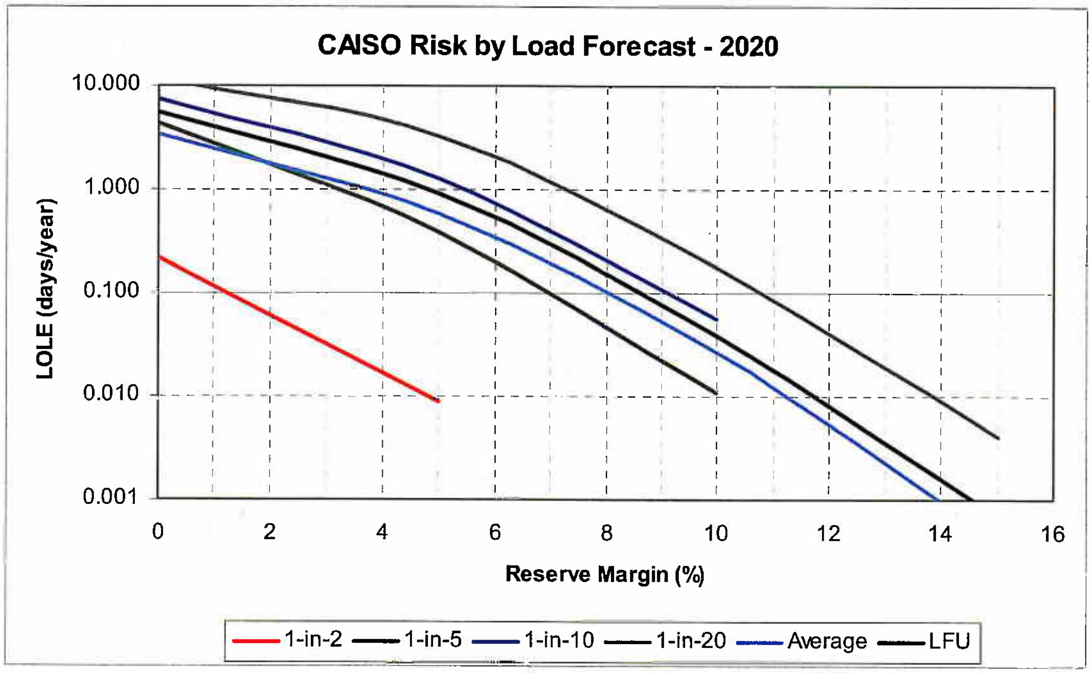


Figure 11 - CAISO Risk by Load Forecast – 2020

EXTREME LOAD AND HYDRO

This set of sensitivities determined the impact on the PRM of loads being greater than expected and available hydro energy being less than expected. For the extreme load conditions, we assumed the 1-in-20 load forecast. The extreme hydro conditions assumed monthly available energy from the hydro plants equal to 53% of the Base Case hydro conditions.

The LOLE as a function of reserve margins for the extreme load and hydro conditions are shown in Figure 12. The extreme load conditions, represented by the 1-in-20 forecast, added about two percentage points to the Base Case PRM for year. However, the extreme hydro conditions had no impact on the PRM. This is in sharp contrast to the 2008 study in which the drought hydro conditions had a significant impact, but that was with monthly reserve margins and before unused hydro energy was carried forward from one month to the next. With an annual reserve margin and carrying forward the unused hydro energy, combined with the increased diversity of the loads in the current study, the amount of energy available to the hydro units is no longer a significant factor.

When the extreme load and extreme hydro conditions were combined, the plot of the LOLE as a function of reserve margin is nearly identical to that of the extreme load conditions alone, as would be expected from the impact of the extreme hydro conditions alone.

To measure the impact of the assumption that unused hydro energy could be carried forward for use in future months, the extreme hydro scenario was run without the carryforward option. The results, shown in Figure 13, indicate an increase in the PRM of approximately one percentage point, increasing it to 9.2% in 2010 and 9.4% in 2015 and 2020.

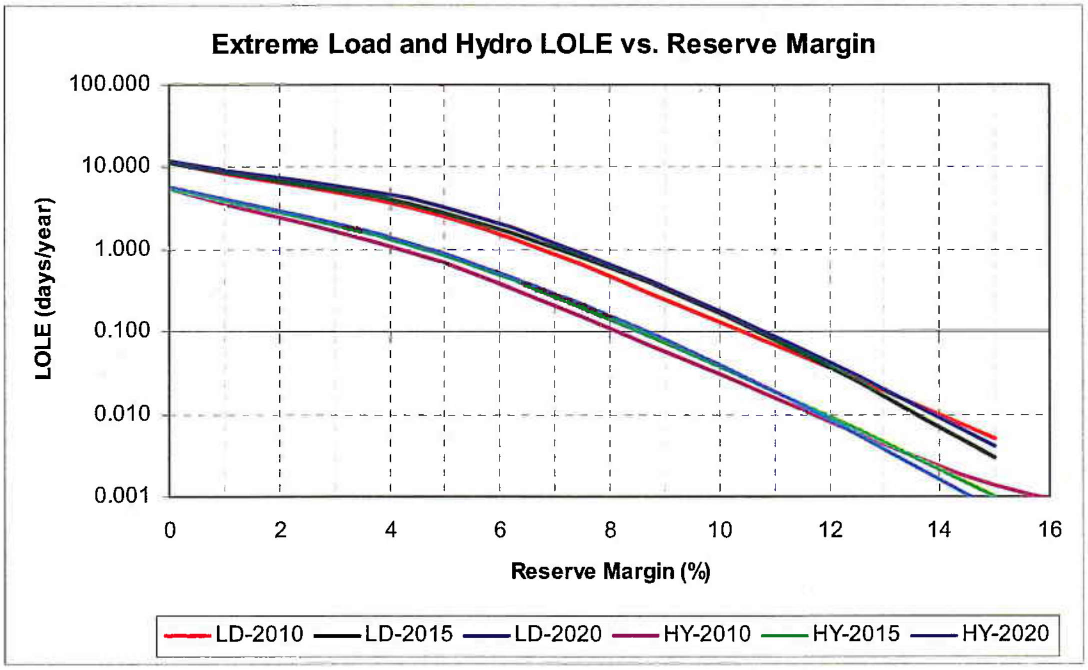


Figure 12 - Extreme Load and Hydro Conditions

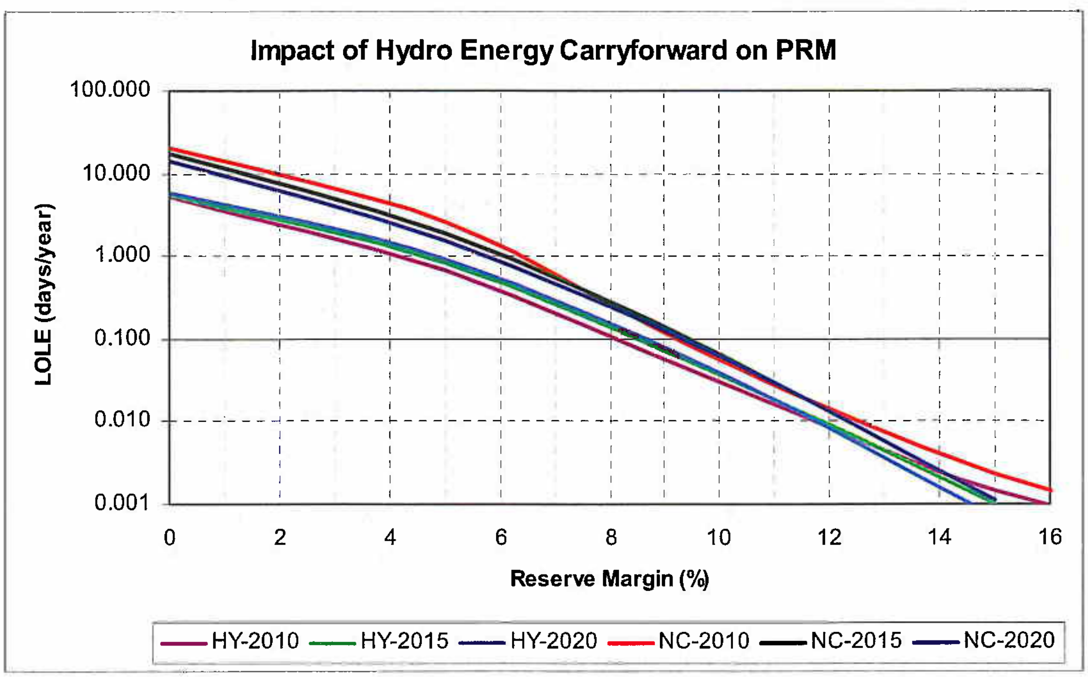


Figure 13 - Impact of Hydro Energy Carryforward

INCREASED FORCED OUTAGE RATES

One of the key assumptions in determining the reserve requirements is the forced outage rate data for the generating units. The forced outage rate data assumed in the Base Case is summarized in Table 6. For this scenario, which was run for only 2010, we assumed that the forced outage rates (EFORd) for all of the generating units were increased by 25%. The impact on the CAISO LOLE is shown in Figure 14 and increased the reserve requirements by about two percentage points for a PRM of 10.3%.

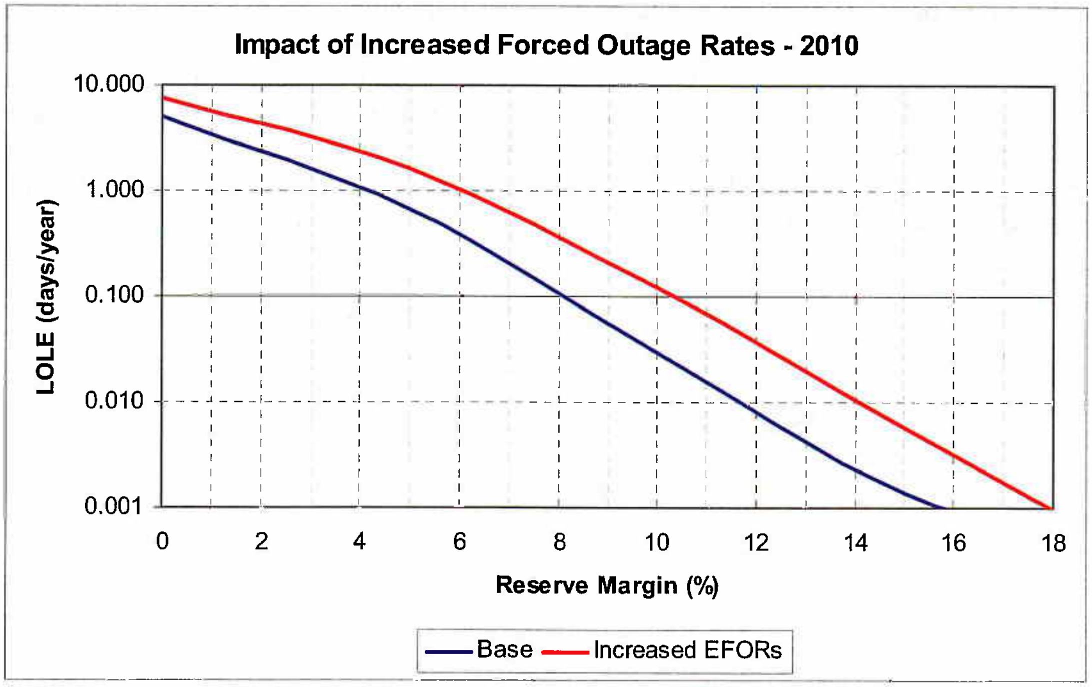


Figure 14 - Impact of Increased Forced Outage Rates – 2010

OTC UNIT RETIREMENTS

The next set of cases focused on the impact on the 2015 and 2020 PRM of retiring the OTC units as an extreme study scenario in response to the SWRCB-proposed implementation policy. In 2015, with only 1,216 MW of OTC units retired resulting in a CAISO reserve margin of nearly 23%, the LOLE for the existing system was still 0.0 days/year, as in the Base Case. Consequently, the same methodology for determining PRM that had been used in all of the cases thus far (adding or removing perfect capacity to model a given level of installed reserves) could be used.

As shown in Figure 15, the PRM for 2015 decreased slightly, from 8.5% to 8.3%. The small amount of change was due to the relatively small amount of capacity retired, and the decrease reflects the fact that the average forced outage rates of the OTC units was slightly higher than for the rest of the units. With those units removed, a given level of reliability could be maintained with slightly lower installed reserves.

By 2020, 13,415 MW of OTC units were retired, reducing the CAISO reserve margin to –6.6% and increasing the LOLE to 7.562 days/year. Since adding perfect capacity to bring the system to 0.1 days/year would understate the required reserves, we added 500 MW combined cycle units with a forced outage rate of 6.33% to replace the OTC capacity.

To be consistent with the methodology used to this point, the units were added to the areas so that all three areas would be at a given level of installed reserves at the time of the CAISO peak. If capacity had to be removed from an area to model a given level of reserves, it continued to be removed in the form of perfect capacity. For example, to model each area at 10% reserves, 1,303 MW of perfect capacity was removed from Northern California, while 8,322 MW of combined cycle capacity (sixteen 500 MW units and one 322 MW unit) was added to Southern California, and 2,177 MW of combined cycle capacity was added to San Diego. As stated above, the combined cycle units added were modeled with a 6.33% forced outage rate.

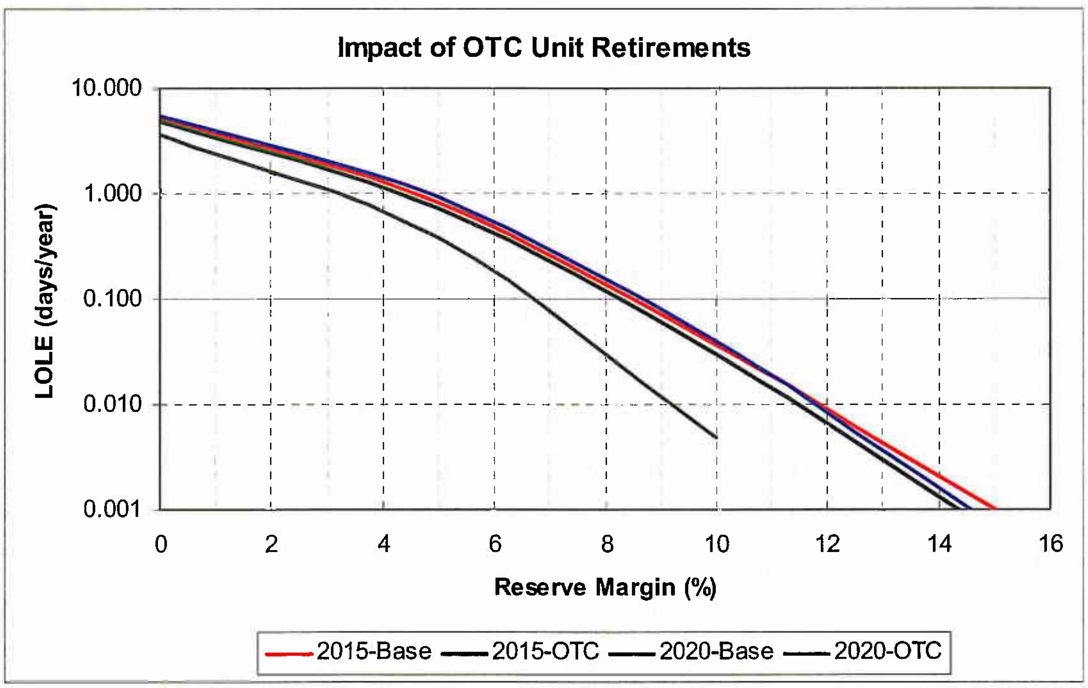


Figure 15 - Impact of OTC Retirements

The resulting PRM for 2020, as shown in Figure 15, was 6.7% compared to 8.7% in the Base Case. To meet this PRM in each of the area, 2,080 MW of perfect capacity was removed from Northern California, 7,443 MW of combined cycle capacity was added to Southern California, and 2,009 MW of combined cycle capacity was added to San Diego. The decrease in PRM once again reflects the lower forced outage rate of the new units compared to the units that they replaced, combined with the lesser amount of perfect capacity that must be removed from Northern California.

INCREASED RENEWABLES

These cases considered increased levels of renewables, specifically a 20% Renewables Portfolio Standard (RPS) case for 2015 and a 33% RPS case for 2020. For each year, the additional input data included the load profiles of the renewables to be added to the system and the list of thermal units to be removed to make room for the desired energy output from the renewable generation.

It is important to note that a PRM study such as this one addresses only the amount of installed capacity required to meet a specific reliability metric, such as an LOLE of 0.1 days per year, which is an industry standard accepted at most major Regional Transmission Organizations (RTOs), ISOs, and other reliability organizations. **The PRM study does not address operational issues** related to the integration of renewables, such as ramping requirements needed for load following and regulation, nor local reliability requirements. Based on the results of CAISO's *Integration of Renewable Resources* study conducted in 2007, (http://www.caiso.com/1ca5/1ca5a7a026270.pdf), all of the existing generating resources within the ISO Balancing Authority Area are needed to provide operational support to meet the State's 20% Renewables Portfolio Standard (RPS) mandate, and possibly more generating resources are needed to meet the State's 33% RPS target. CAISO is currently evaluating the operational needs to meet the State's 33% RPS target.

It also is worth noting that the PRM study is not based on the actual behavior of the wind generation in the three summer months but the data inputs are based on hourly generation profiles provided by National Renewable Energy Lab (NREL) for the location, type and their corresponding capacity provided by E3/CPUC as part of the "Unified Vision" for 33% RPS target in 2020. Though apparently NREL's characteristics of renewable profiles can be considered optimistic in nature, with more than 70% of the renewable additions having profiles that yield an annual capacity factor more than 39%, NREL engineers justified their calculated value on good wind speed and new wind turbine design that can start producing at a lower wind speed as well as can sustain higher wind gust

The first step in the analysis of renewables was to determine the capacity value of the additions. The capacity value of a given renewable addition can be expressed in terms of perfect or some other type of non-intermittent generation that has the same reliability impact as the renewable generation.

In 2015, the reserve margin for the "as-found" system was 25.3%. When the 5,487 MW of thermal units was removed from the system to make room for the desired energy from the renewable generation, the reserve margin was 14.7% and the LOLE was still 0.0 days/year. In this case, the renewables would have no capacity value in terms of the CAISO LOLE since adding them to the system would have no impact on the risk, due to the initial high "as-found" reserve margin of 25.3%.

In 2020, when the 9,368 MW of thermal capacity was removed, CAISO reserve margin dropped from 17.6% to 0.7% and the LOLE increased from 0.0 days/year to 1.126 days/year. For the mix of renewables being added to the system and their corresponding hourly profile, 18,283 MW of renewables (based on their maximum output for August) was added to get the desired energy output of 33% of total load energy in 2020, and the CAISO LOLE improved to 0.0 days/year.

To determine the capacity value of the renewables, we started with the 2020 system, with the renewable additions, and removed perfect capacity in blocks of 1,000 MW, split between the areas in proportion to the amount of renewables added to each area. The plot in Figure 16 shows the increase in CAISO LOLE as perfect capacity is removed.

In order to return the system with to the same LOLE (1.126 days/year) as it had before the renewables were added, approximately 6,600 MW of perfect capacity had to be removed. The 18,283 MW of renewables added in 2020 thus had the same reliability benefit as 6,600 MW of perfect capacity, resulting in a capacity value for the renewables, as a group, of approximately 36%.

Although this value may seem to be high considering that the new renewables had an annual capacity factor (based on the August ratings) of 38.5%, a review of the hourly profiles and penetration of the different profiles indicates that this value is reasonable.

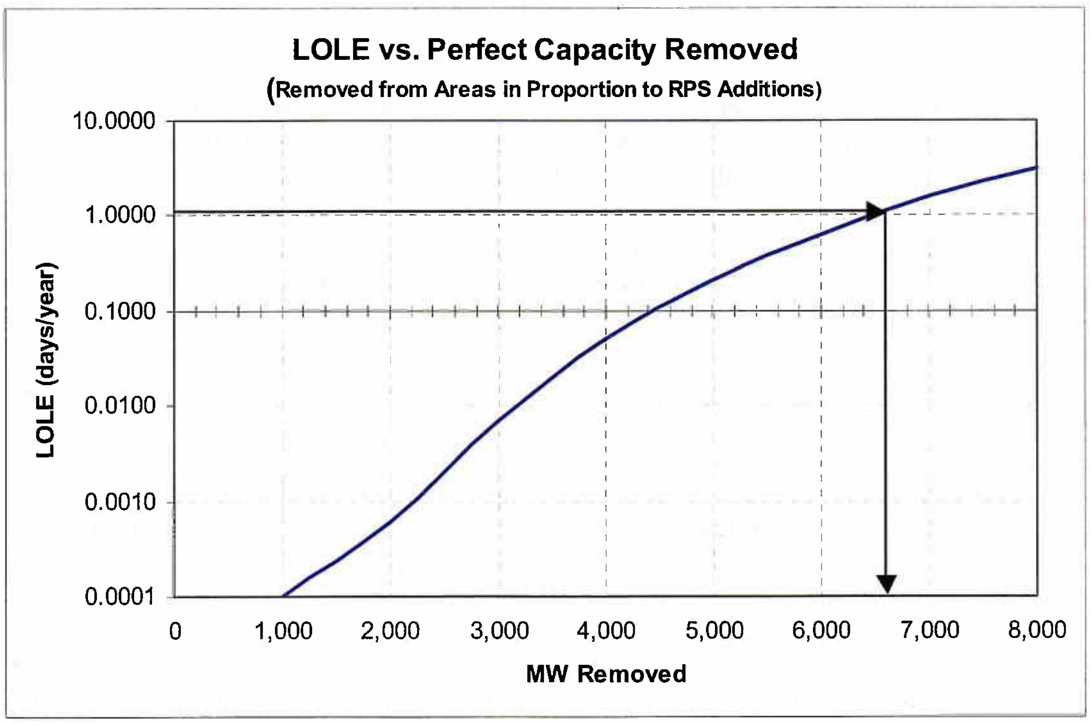


Figure 16 - LOLE versus Perfect Capacity Removed

A total of eight unique shapes were specified for modeling the 131 renewable additions in 2020. The number of units assigned to each shape, along with the total capacity (based on maximum output during August), percent of total renewable additions, and annual capacity factor, are shown in Table 10.

Table 10 - Characteristics of Renewable Profiles

Shape	Number of Units	August Capacity (MW)	% of Total Additions	Annual Capacity Factor (%)
1	9	1,505	8.23	19.0
2	15	2,190	11.98	25.3
3	24	529	2.90	36.6
4	38	7,359	40.25	39.4
5	6	1,182	6.46	41.0
6	27	5,479	29.97	43.1
7	1	37	0.20	90.5
8	11	2	0.01	100.0

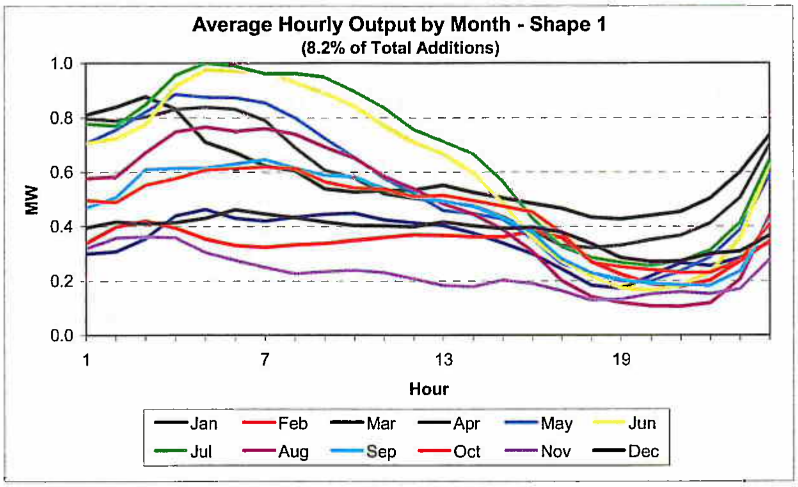
An important factor in the capacity value of an intermittent resource is the output that it provided when it is most need, during the time of the peak loads, both on a seasonal basis and on an hourly basis throughout the day. Figure 17 and Figure 18 show the average hourly output, by month, of the first six shapes, which make up more than 99% of the renewable additions.

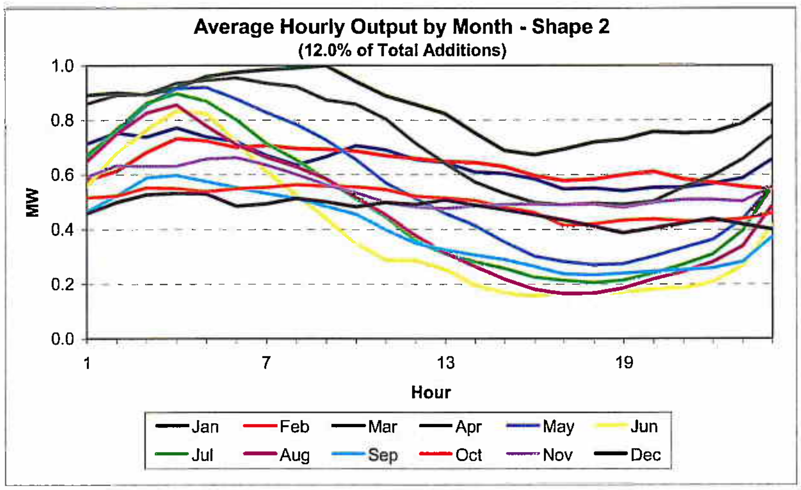
Shapes 3 and 6 appear to represent solar resources, with fairly constant output available for most of the daylight hours. The other four shapes appear to model wind resources for which the output peaks in the early morning hours and then drops off during the day.

Given that 30% of the renewable additions, as represented by Shape 6, are at nearly 90% of their maximum output during the daily peak load hours of the summer months, it's not surprising that the capacity value of the group was 36%.

With 9,368 MW of thermal capacity removed so that 33% of the total load energy[8] could be met by the existing renewable generation (3,468 MW based on maximum output in August, and 18,935 GWh annual output) plus 18,283 MW of additional renewable generation (annual output of 61,837 GWh), the CAISO reserve margin was 33.8% and the LOLE was 0.0 days/year. Perfect capacity was then removed to model the system at a range of reserve margins shown in Figure 19, where the PRM is seen to increase from 8.7% to 27.2%. The significant increase in PRM is the result of capacity value of the renewable additions (36%) compared to that of the generation that they replaced.

[8] Total load energy was calculated by combining the annual energy demand of each load shape using the probabilities of the 1-in-2, 1-in-5, 1-in-10 and, 1-in-20 load forecasts for 2020.





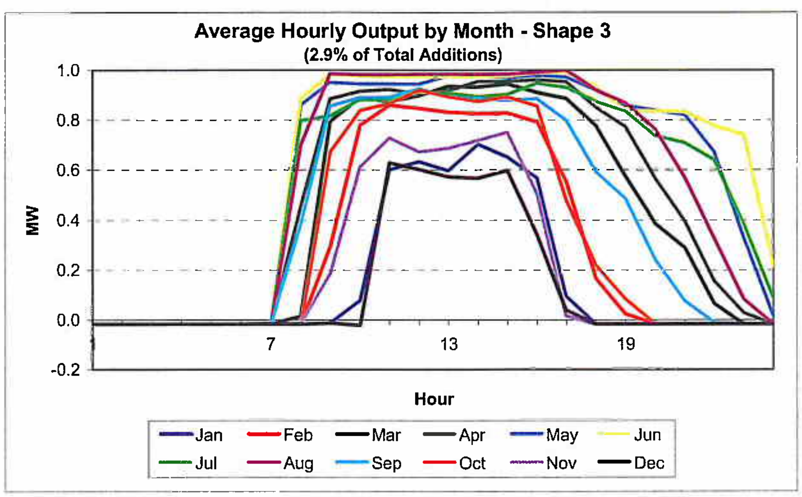
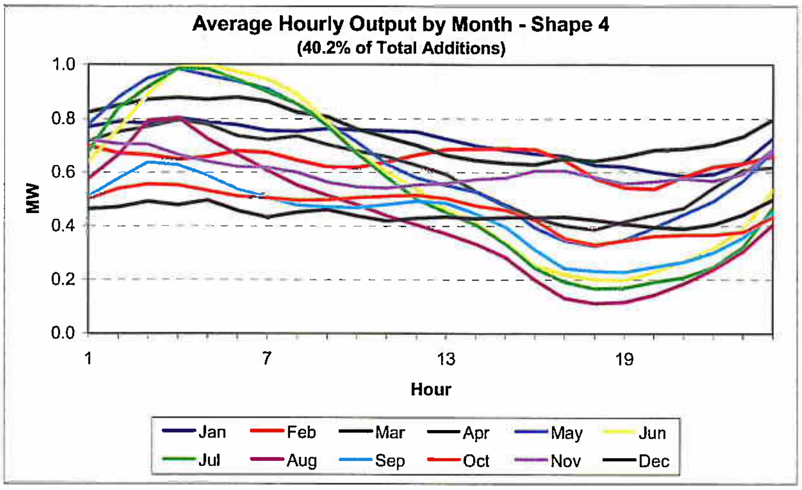
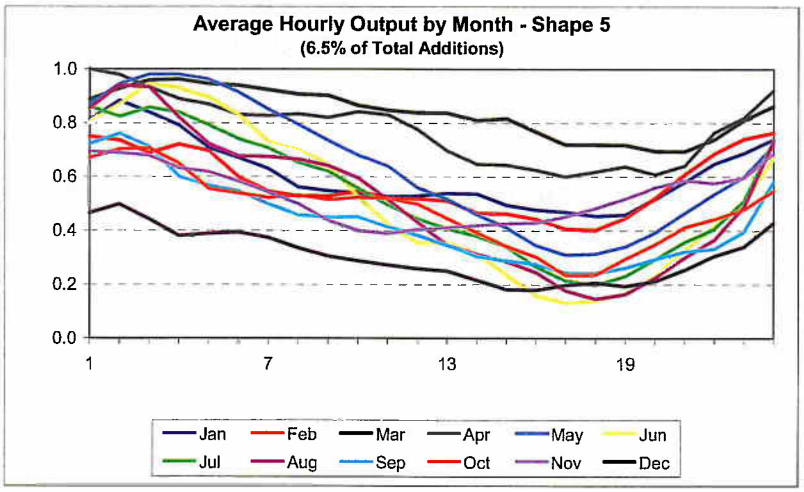


Figure 17 - Average Hourly Output by Month - Shapes 1 - 3





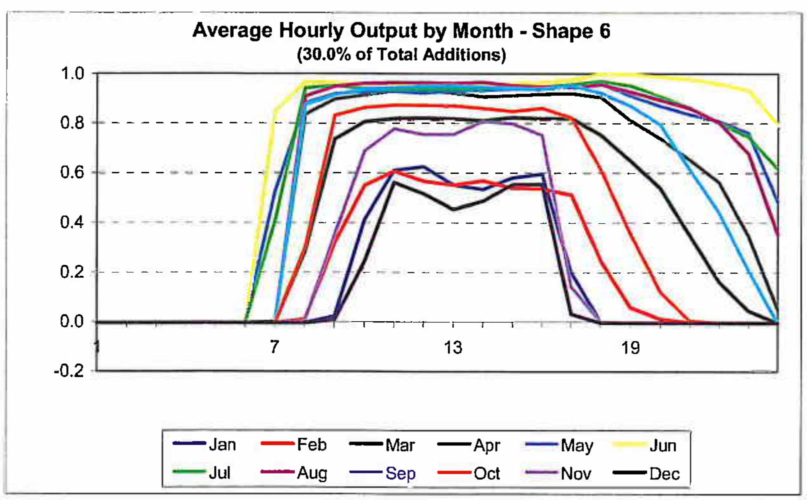


Figure 18 - Average Hourly Output by Month - Shapes 4 - 6

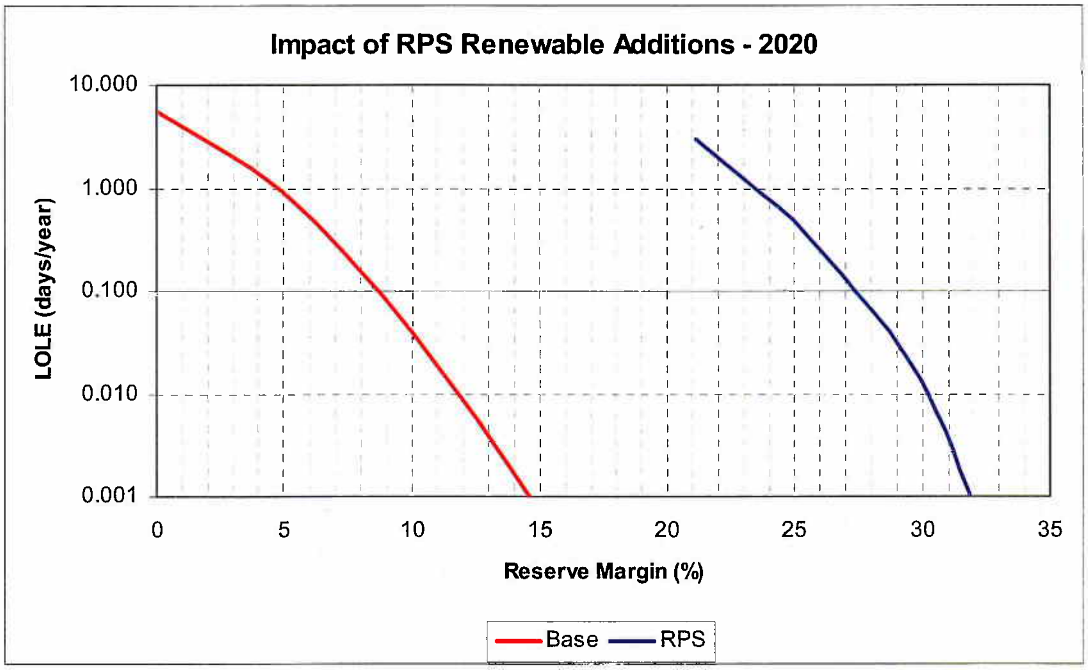


Figure 19 - Impact of RPS Renewable Additions - 2020

5 Conclusions

The current study builds on the data and results of the previous 2008 study to consider a revised Base Case and additional scenarios for 2010 as well as for 2015 and 2020. It is important to note that a PRM study such as this one is intended to address only the energy supply issue in terms of the amount of installed capacity required to meet a specific reliability metric, such as an LOLE of 0.1 days per year, which is an industry standard accepted at most major Regional Transmission Organizations (RTOs), ISOs, and other reliability organizations. **The PRM study does not address operational issues**, local reliability requirements or issues related to the integration of renewables. The ancillary services required to integrate the renewable generation (e.g., ramping, regulation, load following, etc.) may very well require the presence of a larger fleet of generation than that required for energy service purposes as determined by the PRM.

Based on the results of CAISO's *Integration of Renewable Resources* study conducted in 2007, (http://www.caiso.com/1ca5/1ca5a7a026270.pdf), all of the existing generating resources within the ISO Balancing Authority Area are needed to provide operational support to meet the State's 20% Renewables Portfolio Standard (RPS) mandate, and possibly more generating resources are needed to meet the State's 33% RPS target. CAISO is currently evaluating the operational needs to meet the State's 33% RPS target.

It also is worth noting that the PRM study is not based on the actual behavior of the wind generation in the three summer months but the data inputs are based on hourly generation profiles provided by National Renewable Energy Lab (NREL) for the location, type and their corresponding capacity provided by E3/CPUC as part of the "Unified Vision" for 33% RPS target in 2020. Though apparently NREL's characteristics of renewable profiles can be considered optimistic in nature, with more than 70% of the renewable additions having profiles that yield an annual capacity factor more than 39%, NREL engineers justified their calculated value on good wind speed and new wind turbine design that can start producing at a lower wind speed as well as can sustain higher wind gust

The Base Case results indicate the need for an annual PRM in the range of 8% to 9% for the study period. Including just one-half of the imports (3,655 MW) in the reserve margin calculations would increase these values to approximately 15%. The assumption of extreme load conditions, represented by the 1-in-20 load forecast, increased the PRM by approximately two percentage points, to the 10% to 11% range. A 25% increase in the forced outage rates had a similar effect. Assuming extreme hydro conditions had no impact on PRM, but not allowing the carryforward of unused energy from month to month increased the PRM by about one percentage point.

In the once-through-cooling (OTC) scenario for 2020, the retirement of the OTC units reduced the CAISO reserve margin to –6.6% and increased the LOLE to 7.562 days/year. Removing 2,080 MW of perfect capacity from Northern California and adding 7,443 MW of combined cycle capacity to Southern California and 2,009 MW to San Diego improved to LOLE to 0.1 days/year. Replacing the OTC units with combined cycle units with lower forced outage rates, combined with removing less perfect capacity from Northern California, resulted in a slight decrease in the PRM to 6.7%.

In the case of the RPS scenario for 2020, the renewable additions had a capacity value of 36% because of hourly profiles that peaked, to a large extent, during the same hours as the daily loads. However, replacing thermal capacity with these renewable additions significantly increased the PRM from 8.7% to 27.2%.

Appendix A – MARS Program Description

The Multi-Area Reliability Simulation software program (MARS) enables the electric utility planner to quickly and accurately assess the reliability of a generation system comprised of any number of interconnected areas.

MARS MODELING TECHNIQUE

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

RELIABILITY INDICES AVAILABLE FROM MARS

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- LOEE (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

DESCRIPTION OF PROGRAM MODELS

Loads

The loads in MARS are modeled on an hourly, chronological basis for each area being studied. The program has the option to modify the input hourly loads through time to meet specified annual or monthly peaks and energies. Uncertainty on the annual peak load forecast can also be modeled, and can vary by area on a monthly basis.

GENERATION

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management are modeled as load modifiers.

For each unit modeled, the user specifies the installation and retirement dates and planned maintenance requirements. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

Thermal Units. In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as a result of the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\text{TR (A to B)} = \frac{\text{Number of Transitions from A to B}}{\text{Total Time in State A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transitions rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units. Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration. MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM. Energy-storage units and demand-side management are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week, which is subtracted from the hourly loads for the unit's area.

TRANSMISSION SYSTEM

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

The transfer limits are specified for each direction of the interface or interface group and can be input on a monthly basis. The transfer limits can also vary hourly according to the availability of specified units and the value of area loads.

CONTRACTS

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

EMERGENCY OPERATING PROCEDURES

Emergency operating procedures are steps undertaken by a utility system as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements, which can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for a utility to begin emergency operating procedures is modeled in MARS by evaluating the daily LOLE at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The user can also specify monthly limits on the number of times that each emergency procedure is initiated, and whether each EOP benefits only the area itself, other areas in the same pool, or areas throughout the system. Staggered implementation of EOPs, in which the deficient area must initiate a specified number of EOPs before non-deficient areas begin implementation, can also be modeled.

RESOURCE ALLOCATION AMONG AREAS

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls.

The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

OUTPUT REPORTS

The following output reports are available from MARS. Most of the summaries of calculated quantities are available for each load forecast uncertainty load level and as a weighted-average based on the input probabilities.

- Summary of the thermal unit data.
- Summary of installed capacity by month by user-defined unit type.
- Summary of load data, showing monthly peaks, energies, and load factors.
- Unit outage summary showing the weeks during the year that each unit was on planned outage.
- Summary of weekly reserves by area, pool, and system.
- Annual, monthly, and weekly reliability indices - by area and pool, isolated and interconnected.
- Expected number of days per year at specified margin states on an annual, monthly, and weekly basis.
- Annual and monthly summaries of the flows, showing for each interface the maximum and average flow for the year, the number of hours at the tie limit, and the number of hours of flow during the year.
- Annual summary of energy and hours of curtailment for each contract.
- Annual summary of energy usage for the peaking portion of Type 2 energy-limited units.
- Replication year output, by area and pool, isolated and interconnected, showing the daily and hourly LOLE and LOEE for each time that the study year was simulated. This information can be used to plot distributions of the indices, which show the year-to-year variation that actually occurs.
- Annual summary of the minimum and maximum values of the replication year indices.
- Detailed hourly output showing, for each hour that any of the areas has a negative margin on an isolated basis, the margin for each area on an isolated and interconnected basis.
- Detailed hourly output showing the flows on each interface.

PROGRAM DIMENSIONS

All of the program dimensions in MARS can be changed at the time of installation to size the program to the system being studied. Among the key parameters that can be changed are the number of units, areas, pool, and interfaces.