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March 1, 2010

VIA MESSENGER

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20246

Re: ***California Independent System Operator Corporation***
Docket No. ER10-319-___

Response to the January 29, 2010 Letter – Contains Privileged Materials

Dear Secretary Bose:

On November 25, 2009, the California Independent System Operator Corporation ("ISO")[1] filed an amendment to its tariff in the above-referenced proceeding ("November 25 Tariff Amendment").[2] On January 29, 2010, Commission Staff sent the ISO a letter ("January 29 Letter") requesting additional information. In response to the January 29, 2010 letter, the ISO provides six copies of information in the instant filing. As explained in Section II, below, the ISO requests privileged treatment for a portion of that information.

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1 The ISO is sometimes referred to as the CAISO. Capitalized terms not otherwise defined herein have the meanings set forth in Appendix A to the ISO tariff.

2 The ISO sent the November 25 Tariff Amendment to the Commission via overnight delivery on November 24, 2009.

Two additional copies of this filing are also being provided to the Commission Staff, consistent with the directives in the January 29 Letter. An additional copy of this filing is provided to be date-stamped and returned to our messenger.

I. Responses to Questions in the January 29 Letter

The questions from Commission Staff contained in the January 29 Letter, and the ISO's responses to those questions, are provided below.

1. Question. *Please provide justification for the CAISO's use of 1 MW as the proposed reduced threshold for outage reporting by Eligible Intermittent Resources.*[3] *Explain the impact to system reliability from a less stringent forced outage reporting threshold, e.g., 2 MW, or 5 MW, or even 9 MW. Provide all supplemental documentation and analysis which have already been prepared, including existing cost benefit analyses of the 1 MW figure and all other potential alternatives. Fully discuss alternative approaches considered and rejected in favor of the proposal, and why they were rejected.*[4]

   Response. In order to address this question, the ISO believes it is important first to clarify the overall objectives of how the ISO will improve its operational practices related to intermittent resources like wind and solar generation. As explained below, the 1 MW threshold for outage reporting by Eligible Intermittent Resources is consistent with these objectives and reflects the physical characteristics of the typical new wind farm being constructed in the ISO balancing authority area.

   As explained in the attached declarations of James Blatchford, Senior Stakeholder Engagement and Policy Specialist for the ISO and Clyde Loutan, Senior Advisor for the ISO, the ISO has determined that it needs better information on the expected output of wind and solar generation in order to address the operational challenges created by the integration of large amounts of intermittent resources into the electric system operated by the ISO. The tariff revisions proposed in the November 25 Tariff Amendment are designed to ensure that the ISO will have the information needed to address these operational challenges.

[3] This should include analysis beyond that which was provided in its November 25, 2008 root cause study, which recommended, evidently without support, that forced outages be reported at the 1 MW level. *See* CAISO December 31, 2009 Answer at 5 n.4 (citing *Improving Forecasting Through Accurate Data* (Nov. 2008), *available at* http://www.caiso.com/208a/208a86fd68120.pdf (2008 Root Cause Study)).

[4] The Commission has raised the outage reporting requirement threshold issue in its recent Notice of Inquiry related to variable energy resources, issued in Docket No. RM10-11-000. *Integration of Variable Intermittent Resources*, 130 FERC ¶ 61,053 (2010).

Improved information on the expected real-time output of wind and solar generation will allow the ISO's operators to make better unit commitment and dispatch decisions in advance of real-time. As explained by Mr. Blatchford, the new requirements for all Eligible Intermittent Resources proposed in the November 25 Tariff Amendment will allow the ISO's independent forecast provider to provide the ISO with a much more detailed forecast of the expected output of wind and solar resources. The ISO's operators and software systems will incorporate this forecast information into a probabilistic approach to making dispatch and unit commitment decisions.

Improved information on the expected real-time output of wind and solar generation will also allow the ISO to limit the procurement of regulation and load-following services associated with intermittent resources. Regulation is generating capacity under automatic generation control that is used to continuously balance supply (including interchange schedules) and real-time load on the ISO system. Load-following is the dispatch of energy in the real-time market to address longer-term imbalances that are not addressed by regulation. The ISO does not have a separate market for obtaining load-following services but instead performs load-following by dispatching resources that have submitted bids to provide energy in the real-time market. More details on the regulation and load-following features of the ISO's markets and software systems are provided by Mr. Loutan.

As explained by Mr. Loutan, a certain portion of regulation and load-following services that the ISO must procure through the ISO markets are attributable to the inherent variable nature of wind and solar resources. An additional incremental amount of regulation and load-following services are attributable to forecast errors, *i.e.*, flaws in the system operator's current forecast of intermittent resource output. Better information on the anticipated real-time production of intermittent resources will allow the ISO to reduce the regulation and load-following services attributable to intermittent forecast error. The relationship between intermittent forecast error and load-following services is particularly dramatic. As Mr. Loutan explains, based on an analysis using estimated data for 2012, for the spring season, wind forecast error constitutes approximately 33 percent of load-following up and load-following down requirements. Details on this analysis are provided in Mr. Loutan's declaration.

The ISO's need for more accurate forecasting of production from Eligible Intermittent Resources will only increase as such resources become a larger part of the total amount of the portfolio of resources in California. Currently, there are approximately 3,500 MW of wind and solar generation in the ISO balancing authority area to serve a peak load of approximately 50,000 MW. Those amounts are expected to increase dramatically throughout the decade. Pursuant to California's Renewable Portfolio Standard ("RPS") legislation (SB 107), electric corporations are required to increase procurement from eligible renewable energy resources by at least 1 percent of their retail sales annually, until they reach 20 percent by the end of 2010, although the California Public Utilities Commission has subsequently stated that 2013-14 is a more realistic date for reaching this 20 percent level.[5] Further, the Governor of California has issued an executive order (S-14-08) that sets a target for renewable energy resources to supply 33 percent of the power to California by 2020.[6]

As to the effect that intermittent resources constructed to satisfy the RPS requirements may have on the ISO's operations if the ISO's forecasting is inaccurate, the ISO issued a paper in 2007 that explained:

> Currently, uncertainty associated with forecasting the output levels of intermittent resources in the DA [day-ahead] time frame do not pose any reliability concerns because the actual wind generation output is typically less than 1,100 MW. As shown in Figure 4-1, with the 20% RPS build out, wind generation may peak as high as 6,000 MW, and production levels could exceed 2,000 MW for approximately 50% of the year. *A lack of DA forecasts for this amount of wind generation could result in significant reliability issues*.[7]

These reliability issues include the potential for insufficient resources committed through the Residual Unit Commitment ("RUC") process to meet the ISO's next-day hourly demand.

A lack of accurate outage information by intermittent resources can detrimentally affect the ISO's forecasts. As the ISO concluded in another report issued in April 2008:

> This analysis presented in this report indicates that the relative performance of both the PIRP [Participating Intermittent Resource Program] next operating hour and day-ahead forecasts is closely linked to the quantity and quality of the power production, *turbine availability* and meteorological data from each PIR [Participating

5 *See* CPUC report entitled *Renewables Portfolio Standard Quarterly Report – Q4 2009*, at 4. This report is available on the CPUC's website at http://www.cpuc.ca.gov/NR/rdonlyres/52BFA25E-0D2E-48C0-950C-9C82BFEEF54C/0/FourthQuarter2009RPSLegislativeReportFINAL.pdf.

6 *See* http://www.cpuc.ca.gov/PUC/energy/Renewables/overview; http://docs.cpuc.ca.gov/word_pdf/report/85936.pdf.

7 *Integration of Renewable Resources* (Nov. 2007), at 49 (emphasis added). This report is provided in Attachment C hereto and is available on the ISO's website at http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

> Intermittent Resource]. In general, the analysis suggests that there was a *significant negative impact on the overall PIRP forecast performance due to PIR data issues, which included* large amounts of missing data, relatively unrepresentative meteorological data and *misreported turbine availability information*. The analysis of the data indicates that the overall degradation of the MAE [mean absolute error] for both the next operating hour or next day forecasts was about 20% relative to what could have been achieved if all the PIRs had provided a high level of data quantity and quality (i.e. similar to what was provided by the best PIR data provider). A similar degradation in the performance as measured by other metrics (e.g. magnitude of the net month deviation, root mean square errors etc.) can be inferred from the analysis of the available performance data.[8]

In order to make the reporting of outages by Eligible Intermittent Resources as accurate as reasonably practicable, the ISO determined that it was appropriate to use a 1 MW threshold for outage reporting. The ISO proposes to adopt the 1 MW threshold for a number of reasons. First, approximately 1 MW is the typical size of a single wind turbine in new wind farms being constructed in the ISO balancing authority area. Thus, a 1 MW outage reporting requirement will provide the ISO with information when even a single turbine at a wind farm is out of service. One MW is also the minimum size of a resource that the ISO's systems can recognize as an "intermittent resource," regardless of whether that resource is a wind or solar resource.

As explained above, the existing 10 MW outage reporting requirement resulted in many individual turbine outages going unreported to the ISO, significantly contributing to ISO forecast errors. In order to reduce these errors, the ISO concluded that it was appropriate to reduce the outage reporting threshold for intermittent resources by a single order of magnitude, *i.e.*, from 10 MW to 1 MW. This is also consistent with other provisions of the ISO tariff which require that a generating unit must have a rating of 1 MW or greater to be a Participating Generator.

Even a threshold MW amount that appears to be only somewhat less stringent than the 1 MW threshold can have a significant adverse impact on the accuracy of the outage reporting and thus on the accuracy of the ISO's forecast. For example, assume a 1 MW outage reporting threshold applied to a wind resource

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[8] *CAISO PIRP Wind Power Production Forecast Performance 2007* (Apr. 2008), at 55 (emphasis added). This report is provided in Attachment D hereto. As discussed in Section II, below, the ISO requests privileged treatment for Attachment D because it contains commercially sensitive information. A version of the report that omits the commercially sensitive information is available on the ISO's website at http://www.caiso.com/2083/2083706b19380.pdf.

that is forecasted to produce 50 MW. The outage reporting threshold of 1 MW will ensure that the forecast for the resource has a margin of error of less than 2 percent (*i.e.*, 1 MW divided by 50 MW). If, however, the outage reporting threshold is increased to 2 MW, the potential margin of error in the forecast for the resource will double to 4 percent (2 MW divided by 50 MW). And if the outage reporting threshold is increased to 9 MW, the potential margin of error will increase to 18 percent (9 MW divided by 50 MW).

Using a less stringent threshold than 1 MW would affect the accuracy of the ISO's forecasts not only when the less stringent threshold was first employed, but subsequently as well. The algorithms and neural networks of the forecast service provider for the ISO engage in a training period to correlate the characteristics of an intermittent resource to its fuel source. Part of the algorithm is an input from the ISO's outage reporting system. Once the forecast service provider's algorithm has "learned" the resource's characteristics, undisclosed changes to the energy availability will affect the forecast. Accordingly, the use of a less stringent threshold would increase the likelihood that the forecasting algorithm would accumulate inaccurate data (*i.e.*, undisclosed outages) in its knowledge base, which would lead to the calculation of further erroneous energy forecasts.

The ISO's decision to use the 1 MW value rather than some other value satisfies the requirements of Section 205 of the Federal Power Act ("FPA"). As the Commission has explained, "the courts and this Commission have recognized that there is not a single just and reasonable rate. Instead, we evaluate [proposals under Section 205] to determine whether they fall within a zone of reasonableness. So long as the end result is reasonable, the [proposal] will satisfy the statutory standard."[9] For the reasons the ISO has explained in this proceeding, the Commission should find that the end result of using the 1 MW threshold will be reasonable.

The ISO prepared no analyses comparing the 1 MW threshold to other alternatives, because the ISO concluded that the 1 MW threshold was appropriate for the reasons described above and no stakeholder suggested that the ISO should consider a different threshold. Further, no party in this proceeding or the stakeholder process has provided any evidence showing that the proposed obligation to report intermittent resource outages of 1 MW or more would impose a burden that is substantively greater than a requirement to report outages that is based on less stringent MW thresholds. Indeed, one stakeholder, VIASYN, commented that it enters outages as small as 1 MW "into SLIC more

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[9] *Calpine Corp. v. California Independent System Operator Corp.*, 128 FERC ¶ 61,271, at P 41 (2009) (citations omitted). *See also New England Power Co.*, 52 FERC ¶ 61,090, at 61,336 (1990), *aff'd*, *Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992) (rate design proposed need not be perfect, it merely needs to be just and reasonable).

or less daily and hourly if needed and it is neither difficult nor time consuming. As long as the wind (or solar) facility has a system that alerts them when a turbine (or panel) is malfunctioning and they know how much energy they are capable of generating, then it is simple to keep their availability updated in SLIC."[10] Thus, the use of the 1 MW threshold will not put an undue burden on intermittent resources participating in the ISO's markets.

2. *Question. Are there differences between intermittent resources and other generation resources that justify requiring the more extensive forced outage reporting for intermittent resources? Do non-intermittent, similarly-sized generation resources have to install the telemetry equipment included in the proposal and, if not, what distinguishes intermittent resources from other generation resources that support the extra telemetry and forecasting installation requirements?*

Response. Yes, there are differences between intermittent resources and non-intermittent resources that justify requiring appropriately tailored forced outage reporting for intermittent resources. For non-intermittent resources, the ISO's expectations of the real-time output of such resources are based on the amount of scheduled energy output, and the predictable nature of those resources' fuel sources means that the ISO can expect that the expectations will be accurate, barring an outage or a *force majeure* event. In contrast, for intermittent resources like wind and solar generators, the ISO's expectations of the real-time output of such resources are subject to an inherent level of uncertainty based on the variable nature of the intermittent resources' fuel sources. The most that the ISO can expect is a probabilistic indication that the supply forecasts for intermittent resources will likely be accurate, and those forecasts can be rendered inaccurate either by the actual generation of an improbably larger or smaller amount of output than was forecast, an outage, or a *force majeure* event. Thus, the ISO's forecasts for intermittent resources like wind and solar generators are necessarily less accurate than the ISO's forecasts for non-intermittent resources. In order to reduce the gap in accuracy between forecasts of intermittent resource output in real-time and forecasts of non-intermittent resource output in real-time, it is appropriate for the ISO to require intermittent resources to provide more granular forced outage reporting. Although the nature of forecasting intermittent resource supply makes it impossible for the ISO to eliminate the gap entirely, the ISO should be permitted to take all reasonable steps to minimize it.

Another difference between intermittent resources and other generation resources that justifies requiring more granular forced outage reporting for intermittent

[10] This VIASYN comment is provided as Attachment E hereto and is available on the ISO's website at http://www.caiso.com/2393/2393b26d63e10.pdf.

resources is the additional regulation and load-following services associated with intermittent resources. As Mr. Loutan explains, a portion of those regulation and load-following services is attributable to the variable nature of such resources while an additional portion of such services is attributable to forecast errors for such resources. The more granular forced outage requirements will reduce forecasting error associated with intermittent resources and therefore allow the ISO to reduce the costs of load-following services and regulation procured by the ISO.

It is also appropriate to apply resource-specific telemetry and forecasting installation requirements to intermittent resources. These resource-specific telemetry and forecasting requirements are necessary because the output of wind and solar generators, unlike other types of resources, are directly linked to localized meteorological conditions which can vary considerably even within a single wind farm or solar installation.

These additional requirements simply will require intermittent resources to provide data to the ISO that will permit the ISO to better ensure that its forecasts for intermittent resources will be correct. Therefore, like the more extensive forced outage reporting the ISO proposes, the additional telemetry and forecasting installation requirements will reduce the gap in accuracy between forecasts of intermittent resource output in real-time and forecasts of non-intermittent resource output in real-time.

The need for the implementation of both of these components of the November 25 Tariff Amendment will become even greater as more intermittent resources supply power in California. (See the discussion in Response #1, above.) If the ISO's forecasts are not sufficiently able to account for the anticipated production from this increased amount of intermittent resources, the ISO will face an unacceptable risk to reliability and increased costs to procure regulation and load-following services attributable to intermittent resource forecast error that can be reduced or eliminated through the application of properly tailored requirements.

The Commission has recognized on numerous occasions that the different characteristics of intermittent or variable resources like wind or solar generators may justify tariff provisions that treat these resources differently from other resources. For example, when the Commission recently approved a proposal by the Southwest Power Pool ("SPP") to establish a different cost allocation methodology for network upgrades associated with the designation of wind resources as network resources, the Commission stated:

> We find it reasonable for SPP to institute a cost allocation methodology that appropriately addresses the issues created by these location-constrained wind resources, even if it is dissimilar to the allocation methodology for other resources. Dissimilar

> treatment of dissimilar resources does not in and of itself constitute undue discrimination, and we find SPP's distinct treatment of these location- constrained resources is not unduly discriminatory given the facts and circumstances of this case.[11]

Moreover, the Commission has recognized that the operational challenges created by intermittent resources can justify requirements that apply only to wind resources. In approving market rules for the New York Independent System Operator, Inc. ("NYISO") that, among other things, require wind resources to submit real-time bids to reduce their output, the Commission stated:

> We appreciate NYISO's efforts to incorporate wind resources into its transmission system while ensuring that it maintains a reliable and secure transmission system. We find that with this filing NYISO has taken an appropriate step to address the operational issues associated with the development of wind resources.[12]

3. Question. *Please provide full justification for the CAISO's proposal to apply expanded telemetry, forecasting, and communications requirements to all intermittent resources that are subject to a Participating Generator Agreement or Qualifying Facility Participating Generator Agreement. How does this change if generators participate in the voluntary Participating Intermittent Resource Program (PIRP)? What are the costs involved for intermittent resources that will be required to install and maintain the telemetry, forecasting, and communications equipment required by the proposal? Has the CAISO conducted any studies examining the costs and benefits of this proposed requirement? If so, please disclose those results.*

Response. As explained by Mr. Blatchford, there are currently only four wind or solar generators with a total capacity of approximately 7.1 MW that are subject to a Participating Generator Agreement or Qualifying Facility Participating Generator Agreement and that have not yet joined PIRP. Some of these resources are newer resources and may elect to join PIRP once they have greater experience in the ISO's markets. Thus the category of Eligible Intermittent Resources that do not participate in PIRP is very small.

The ISO expects that most owners of Eligible Intermittent Resources that connect to the ISO controlled grid in the future will elect to participate in PIRP. Even if they choose not to participate in PIRP, however, these resources will create

11 *Southwest Power Pool, Inc.*, 127 FERC ¶ 61,283 at P 29 (2009) (citations omitted).

12 *New York Independent System Operator, Inc.*, 127 FERC ¶ 61,130 at P 16 (2009).

operational challenges that the ISO will need to address with improved forecasting.

As explained in Responses #1 and #2, above, due to the operating challenges that intermittent resources present, and due to the fact that it will become more and more necessary to have a better forecast of intermittent generation to address these operating challenges as the amount of intermittent generation increases, it is appropriate to apply the extra telemetry and forecasting installation requirements proposed by the ISO to all such resources interconnecting to the ISO controlled grid. All intermittent resources that are subject to a Participating Generator Agreement or a Qualifying Facility Participating Generator Agreement present the same forecasting challenges. Therefore, it is appropriate to apply the same requirements to all of them.[13]

Examples of the costs involved for intermittent resources that will be required to install and maintain the telemetry, forecasting, and communications equipment are provided in Attachment F hereto, for which the ISO requests privileged treatment of commercially sensitive information. As detailed in those materials, the cost for two separate intermittent resource operators of installing a meteorological station tower required for forecasting and communications purposes under the ISO's proposal is approximately $165,000, and the cost for another intermittent resource operator to install required communications equipment to send turbine-level data to the ISO is $7,500. Beyond obtaining this cost data, the ISO has not conducted studies examining the costs and benefits of the proposed requirements.

As the ISO explained in the November 25 Tariff Amendment, certain types of facilities will be exempt from the expanded forecasting and telemetry requirements.[14] Wind facilities with existing or approved meteorological station tower configurations as of the effective date of the November 25 Tariff Amendment will not be compelled to alter those configurations. Similarly, wind resources without an installed nacelle anemometer as of the effective date of the November 25 Tariff Amendment will not be obligated to retrofit. In addition, small conduit hydroelectric facilities will not be obligated to provide additional forecasting data, at least until such time as the ISO may elect to adopt a forecasting program for such facilities.[15] These exemptions are discussed further

[13] As explained in the answer that the ISO filed in this proceeding on December 31, 2009 (at 10-11) ("December 31 Answer"), the proposals in the November 25 Tariff Amendment are not intended to apply to resources that are not those of a participating generator (*e.g.*, resources that are instead subject to a metered subsystem agreement).

[14] Transmittal Letter for November 25 Tariff Amendment at 4.

[15] Transmittal Letter for November 25 Tariff Amendment at 4. In the December 31 Answer (at 9), the ISO proposed to revise the definition of an Eligible Intermittent Resource in a compliance filing to

in Response #6, below. The entities that receive such exemptions will not be required to pay any costs associated with the expanded forecasting and telemetry requirements.

As Mr. Blatchford explains, Eligible Intermittent Resources will receive an additional benefit associated with these requirements. The ISO's forecast services provider will provide each resource subject to these requirements with a resource-specific forecast that reflects the data for that resource provided to the ISO. These resource-specific forecasts in the aggregate are primary inputs into the system-wide forecast used by the ISO.

The ISO has not conducted any specific studies examining the costs and benefits of this proposed requirement other than the studies mentioned in Response #1.

4. Question. *If PIRP was meant to be a voluntary program that considered the unique characteristics of intermittent resources, how is the imposition of telemetry, forecasting, and communications requirements on all intermittent resources a just and reasonable result? Further, please explain why it is appropriate to treat intermittent resources that otherwise would not choose to participate in PIRP differently. Please explain why it is appropriate to place this requirement on intermittent resources only in light of CAISO Tariff section 7.6.1 that treats PIRP intermittent resources and traditional generation similarly, requiring all such resources that are subject to Participating Generator Agreements or Qualifying Facility Participating Generator Agreements that have total qualifying capacity of 10 MW or greater to install the necessary telemetry and communications equipment.*[16]

Response. PIRP was established as a voluntary program for financial, not operational, reasons. Specifically, as the ISO explained in another Commission proceeding:

> [T]he purpose of the Participating Intermittent Resource Program is to alleviate a Participating Intermittent Resource's exposure to charges for real-time imbalance energy and UDPs [Uninstructed Deviation Penalties] resulting from the fact that the resource operator cannot control the output of the resource so that it stays on its hour-ahead schedule. Under the program, Scheduling Coordinators for Participating Intermittent Resources are required

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exclude small conduit hydroelectric facilities and thus to exclude such facilities from the requirements of the November 25 Tariff Amendment.

16 CAISO, FERC Electric Tariff, Fourth Replacement Volume No. I, Original Sheet No. 100, §7.6.1.

> to submit schedules that are consistent with an hourly energy forecast developed under CAISO supervision. Energy from Participating Intermittent Resources is scheduled in the HASP. The CAISO explains that the Participating Intermittent Resource's real-time deviations are summed over each month, monthly deviations are netted against positive deviations, and the net result is settled at the monthly weighted average real-time LMP at the Participating Intermittent Resource's node.[17]

Although the ISO initially established forecasting and telemetry requirements only for intermittent resources that participate in PIRP, this approach was formulated at a time when intermittent resources represented a relatively small percentage of the overall resource mix in California. As the percentage of intermittent resources in the state has grown dramatically, the ISO realized that it must re-examine the operational data it obtains from intermittent resources.

A Participating Intermittent Resource is subject to different settlement rules and subject to additional scheduling requirements tied to those settlement rules. However the operational impact of a Participating Intermittent Resource is indistinguishable from any other Eligible Intermittent Resource in all respects. The output of all intermittent resources fluctuates with the changing and uncertain availability of their primary fuel source.

As explained above, the ISO has an operational need to obtain data from Eligible Intermittent Resources that minimizes the effect of that variability and uncertainty on the ISO's supply forecasts, and that need will only increase in the future as more Eligible Intermittent Resources interconnect to the ISO controlled grid in order to supply power in California. The purpose of the telemetry, forecasting, and communications requirements that the ISO proposes is to meet the ISO's operational need. Therefore, it is just and reasonable to make all Eligible Intermittent Resources equally subject to those requirements.

Making all Eligible Intermittent Resources subject to the ISO's proposed requirements is consistent with the operational treatment of Eligible Intermittent Resources elsewhere in the ISO tariff. For example, Section 31.5.3.4 of the tariff provides that the ISO's RUC procurement target may be adjusted based on the ISO's forecasted deliveries from Eligible Intermittent Resources. Therefore, the RUC procurement target may be adjusted based on forecasted deliveries from

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[17] *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at P 551 (2006). *See also id.* at P 555 (finding PIRP to be a just and reasonable component of the new ISO market design that went into effect on March 31, 2009). The Commission approved the original version of the PIRP in *California Independent System Operator Corp.*, 98 FERC ¶ 61,327 (2002).

Eligible Intermittent Resources regardless of whether they are Participating Intermittent Resources.

Section 7.6.1(d) of the ISO tariff requires each Participating Generator to take, at the direction of the ISO, actions that include "the provision of communications, telemetry and direct control requirements" as to any Generating Unit with a rated capacity of 10 MW or more.[18] However, nothing in the ISO tariff requires the communications, telemetry, and direct control requirements to be the same or even similar for intermittent resources and for non-intermittent resources. To the contrary, Section 2.2.3 of the currently effective Eligible Intermittent Resources Protocol ("EIRP") requires each Participating Intermittent Resource to "install and maintain the communication equipment required pursuant to Section 3 of this EIRP, and the equipment supporting forecast data required pursuant to Section 6 of this EIRP."[19] Sections 3 and 6 of the EIRP set forth equipment obligations that are specific to intermittent resources and are different from the equipment obligations applicable to non-intermittent resources. In the November 25 Tariff Amendment, the ISO proposes to expand the applicability of the provisions in the EIRP to include all Eligible Intermittent Resources. These changes to the EIRP are appropriate for the reasons the ISO explains in this proceeding.

5. *Question. Please provide the CAISO's justification for applying the forecast fee*[20] *to all intermittent resources that are subject to a Participating Generator Agreement or Qualifying Facility Participating Generator Agreement, regardless of whether or not they elect to participate in the voluntary PIRP. As a voluntary program, intermittent resources that choose not to participate can currently avoid PIRP fees. Explain the appropriateness of a forecast fee levied on intermittent resources that choose not to participate in PIRP.*

Response. The ISO levies the forecast fee in order to pay the costs of the ISO's forecasting service provider. As explained above, the ISO will continue to require those forecasting services, and to a greater extent, as more intermittent resources come on-line to provide power in California. The need to forecast the output of these intermittent resources is an operational issue for the ISO that is triggered by each intermittent resource's choice to interconnect to the ISO's balancing authority area, not the intermittent resource's subsidiary decision

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18 Section 7.6.1(d) also specifies that these requirements must be provided for a Generating Unit with a rated capacity of less then 10 MW that is certified by the ISO to provide ancillary services.

19 The EIRP is contained in Appendix Q to the ISO tariff.

20 CAISO, FERC Electric Tariff, Fourth Replacement Volume No. II, Original Sheet No. 1476-7, App. Q § 2.4.1 (explaining the forecast fee, which can be an amount as high as $0.10 per MWh).

whether it will interconnect to the ISO balancing authority area as a Participating Intermittent Resource or simply as an Eligible Intermittent Resource. Because this operational issue arises from the choice of each intermittent resource to interconnect to the ISO's balancing authority area, it is appropriate to levy the costs of addressing the issue (*i.e.*, the forecast fee) on all intermittent resources that do not obtain an exemption from the forecast fee.

Other independent system operators and regional transmission organizations apply a forecast fee to all intermittent resources that supply power to their respective balancing authority areas. For example, in 2008, the NYISO implemented a non-voluntary centralized wind forecasting mechanism in order to more accurately commit and dispatch wind resources in the New York balancing authority area. Under this system, all wind farms (with the exception of two small farms in service before 2002) are required to collect wind speed and direction data from their farms and transmit it at least once every 15 minutes, 24 hours a day, 7 days a week. In order to recover the costs of the program, the NYISO will charge each wind farm $500 a month plus $7.50 a month per MW of nameplate capacity. Although certain historic facilities are exempt from the fee, consistent with the ISO's proposal, no new wind farms in New York are exempt from this requirement. Daily sanctions for failure to comply are set at the greater of $500, or $20/MW of nameplate capacity, per day until the failure to provide data is cured.[21] In approving these rules, the Commission held that "the proposal to implement a centralized wind forecasting mechanism will allow NYISO to more accurately predict the availability of wind resources which should reduce overall system operating costs."[22] Therefore, the Commission has found that it is just and reasonable for other independent system operators to apply a forecast fee to all intermittent resources in their balancing authority areas. The Commission should find likewise for the California ISO.

Further, the forecast fee will not impose an undue burden on intermittent resources. As explained in the November 25 Tariff Amendment, the amount of the forecast fee is limited to the level necessary for the ISO to recover its projected annual costs related to developing energy forecasting systems, generating forecasts, validating forecasts, and monitoring forecast performance, up to a current maximum fee of $0.10 per MWh of metered energy. To determine the amount of the forecast fee, the aggregate program costs incurred by the ISO will be divided by the projected annual energy production of all forecast fee payers. As more intermittent resources take part in the California markets, the per-MWh charge will drop significantly due to the production of more energy

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21 *See* NYISO Market Services Tariff, Section 5.8a (entitled "Collection and Communication of Meteorological Data by Intermittent Power Resources that Depend on Wind as Their Fuel").

22 *New York Independent System Operator, Inc.*, 123 FERC ¶ 61,267 at P 14 (2008).

by intermittent resources.[23] In addition, as discussed in the November 25 Tariff Amendment and in Response #6, below, the ISO will grant an exemption to relieve small existing resources that have historically been exempt from ISO tariff requirements from having the pay the forecast fee due to potential financial hardship. Therefore, the amount of the forecast fee will decrease over time, and exempted entities that can demonstrate potential financial hardship will not be required to pay the forecast fee.

6. <u>Question</u>. *Explain in detail how the CAISO proposes to use its authority to establish exemptions to any of the above requirements, including waiver of the forecast fee, installation of telemetry, forecasting, and communications equipment, and forced outage reporting requirements in its Business Practices Manual. Explain how this authority mitigates concerns that intermittent resources will not be unduly burdened by the proposed CAISO Tariff provisions. What specific criteria and standards will the CAISO apply to assess whether to exempt an intermittent resource from any or all of these requirements? Explain why such reserved authority should not be an explicit tariff requirement and/or require prior Commission authorization.*

<u>Response</u>.

Tariff exemptions and limitations on applicability of expanded data reporting requirements.

The ISO has included the most significant exemptions and limitations on the applicability of its proposed tariff revisions for expanded data reporting by Eligible Intermittent Resources in the tariff revisions themselves. In particular, the expanded forced outage reporting requirements of tariff sections 9.3.10.3(b) and 9.3.10.3.1(b) are limited to resources 10 MW or larger. This effectively exempts smaller resources for which implementing the computer functionality to meet the expanded outage reporting requirements might pose a financial hardship relative to their expected revenues. These tariff sections also limit the penalties applicable to any failure to comply with these additional outage reporting requirements in order to reduce the potential hardship from the expansion of these outage reporting requirements. Thus, (1) the ISO has appropriately incorporated the most significant of its proposed exemptions and limitations on the applicability of its expanded data reporting requirements directly into the tariff, and (2) these exemptions and limitations minimize the possibility that intermittent resources might be unduly burdened by the expanded data reporting requirements set forth in the proposed tariff revisions.

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[23] Transmittal Letter for November 25 Tariff Amendment at 6-7.

In addition, the ISO proposed in its December 31, 2009 Answer to make further revisions to the tariff to remove small conduit hydroelectric facilities from the definition of an "Eligible Intermittent Resource." If the ISO's proposed additional tariff revision is directed by the Commission, then this would effectively incorporate an additional form of exemption into the tariff.

Business Practice Manual exemptions and limitations on applicability of expanded data reporting requirements.

The ISO proposes to establish only a very limited set of standard criteria for exemptions from the requirements for expanded data reporting by Eligible Intermittent Resources in its Business Practice Manual for Market Operations. These very limited BPM criteria for exemptions will supplement the more significant limitations on the expanded data reporting requirements that are set forth in the proposed tariff revisions.

The ISO wishes to clarify that the proposed exemptions would not constitute "waivers" of the generally-applicable tariff requirements. These exemptions would be granted in response to specific requests from entities that meet the very limited set of standard criteria set forth in the BPM. In reserving these particular exemptions for specification in the BPM rather than in the tariff, the ISO has attempted to draw a distinction between those significant enough to merit incorporation in the tariff and those that should be established as a matter of business practice based on potentially changing circumstances for which Commission acceptance each time a minor change is determined to be necessary would be a burden on the resources of the Commission and others.

Even if the Commission were to conclude that the criteria for exemptions from the requirements for expanded data reporting by Eligible Intermittent Resources should be included in the ISO's tariff rather than a Business Practice Manual, the ISO does not believe it is appropriate to require a tariff waiver filing every time the ISO concluded it is appropriate to grant such an exemption. Such a requirement would make the process of obtaining an exemption extremely onerous for intermittent resources, who would first have to support the requested exemption in a request to the ISO and then to obtain legal representation to support the exemption at a Commission proceeding. Requiring a waiver filing would be inconsistent with the ISO's objective of providing timely exemptions where such exemptions are justified. To the extent any party believes the ISO has exercised its discretion to grant an exemption in an improper manner, that party can raise the issue with Commission staff.

The ISO has already proposed its specific BPM criteria for exemptions from the proposed tariff requirements for expanded data reporting in revisions proposed to the BPM for Market Operations associated with BPM Proposed Revision

Request ("PRR") 132 entitled "Document: Proposed PIRP bpm lang 1_04_10 jb.doc" posted on the ISO website at the following link: https://bpm.caiso.com/bpm/prr/show/PRR000000000132. The ISO's proposed exemption criteria are described in detail below. However, the ISO has deferred implementation of these BPM exemption criteria pending the Commission's issuance of an order on the proposed tariff revisions, as they are irrelevant until the Commission accepts the tariff revisions. Consequently, the BPM revisions that the ISO is currently proposing for final decision in the BPM change management process do not include these exemptions, as shown in the revised document associated with BPM PRR 132 entitled "Document: Proposed PIRP BPM lang 2_12_10 final redline.doc" posted on the ISO website at https://bpm.caiso.com/bpm/prr/show/PRR000000000132.

The very limited and less significant exemptions proposed by the ISO in the BPM change management stakeholder process include minor exemptions from the applicability of the forecast fee and from the expanded forced outage reporting requirements. The primary purposes of these proposed exemptions are (1) to relieve small existing resources that have historically been exempt from ISO tariff requirements from the forecast fee due to potential financial hardship and (2) to relieve small conduit hydroelectric facilities from the Forecast Fee and expanded outage reporting requirements, as the requirements are not currently useful for such facilities. The only comment the ISO received regarding these exemptions in the BPM change management stakeholder process was a request that the ISO make the exemption for small conduit hydroelectric facilities more absolute, as discussed further below. If the ISO's proposal in response to comments on the tariff revisions to remove small conduit hydroelectric facilities from the definition of an "Eligible Intermittent Resource" is implemented, this would leave only the single exemption from the forecast fee as reserved to the BPM.

With regard to the expanded forecasting and telemetry requirements, the details of these requirements are set forth in the BPM, so it is only appropriate that limitations on their applicability are also set forth in the BPM. Thus, the ISO has proposed no exemptions from any tariff requirements regarding this aspect of the expanded data reporting requirements. However, to ensure that the ISO provides a sufficient response to the Commission's questions, the limitations that the ISO has proposed in the BPM, and the concerns for potential undue burdens on intermittent resources that they are intended to address, are described further below.

Forecast fee exemptions

1. The ISO has proposed to exempt from the forecast fee resources smaller than 10 MW that are not Participating Intermittent Resources and that previously sold power pursuant to a power purchase agreement entered into pursuant to

the Public Utilities Regulatory Policies Act of 1978. This would relieve small existing qualifying facilities whose "grandfathered" power purchase agreements terminate from having to pay the forecast fee if they choose not to participate in PIRP. This exemption is limited in scope to focus on resources with smaller expected revenues and whose operations have effectively been insulated from ISO tariff compliance for a significant period as having the most potential to suffer a hardship from the application of the forecast fee and as having the least potential impact on system reliability.

2. The ISO has also proposed to exempt small conduit hydroelectric facilities from the forecast fee, unless the ISO commences producing a forecast for this type of facility. In its December 31 Answer, the ISO proposed to remove the listing of this type of facility from the definition of Eligible Intermittent Resource in response to comments from the Metropolitan Water District of Southern California ("MWD"). MWD points out that the variability in the output of this type of facility is subject to decisions made by facility operators and is not subject to the same meteorological forecasting as wind and solar resources. As far as the ISO is aware, (1) MWD is the only entity owning this type of facility in the ISO balancing authority area, (2) there are very few of these facilities in the ISO balancing authority area, and (3) the ISO has no current intention of extending the expanded data reporting requirements to this type of facility. Consequently, the ISO is willing to accommodate MWD's desire to have this type of facility excluded from the definition of an Eligible Intermittent Resource. Pending implementation of a tariff revision to this effect, the ISO has proposed to exempt this type of facility from the forecast fee to minimize the impact of the proposed tariff revisions on this type of facility. Of course, upon implementation of the tariff revision, the exemption would no longer be applicable.

Outage reporting exemption

Similar to the exemption provided from the forecast fee, the ISO has also effectively proposed to exempt small conduit hydroelectric facilities from the expanded requirements for reporting forced outages, unless the ISO commences producing a forecast for this type of facility. As discussed above, the ISO is willing to accommodate MWD's desire to have this type of facility excluded from the definition of an Eligible Intermittent Resource. Pending implementation of a tariff revision to this effect, the ISO has proposed to exempt this type of facility from the expanded forced outage reporting requirements to minimize the impact of the proposed tariff revisions on this type of facility. Upon implementation of the tariff revision, the exemption would no longer be applicable.

Limitations on expanded forecasting and telemetry requirements

As discussed above, the details of the expanded forecasting and telemetry requirements are set forth in the BPM, and the ISO has proposed no exemptions from any tariff requirements regarding this aspect of the expanded data reporting requirements. The limitations that the ISO has proposed in the BPM, and the concerns for potential undue burdens on intermittent resources that they are intended to address, are described below.

1. Regarding the expanded requirements for installation of meteorological equipment, the ISO has proposed limits on implementation that would provide existing facilities six months to comply with the requirement to install a second meteorological station and provide for "grandfathering" of the location and configuration of meteorological stations installed or receiving final regulatory approval by January 2010. (See Response #3, above, and Section A.14.2.2 of the proposed BPM.) This limitation on implementation relieves potential financial hardships of the expanded forecasting and telemetry requirements on existing resources meeting the specified criteria.

2. Regarding the applicability of the expanded forecasting and telemetry requirements generally, the ISO has also proposed to permit multiple resources not participating in PIRP to enter into agreements to use a shared meteorological station to satisfy forecasting and telemetry requirements that would otherwise apply to the resources individually. (See Sections A.14.2.2 and A.14.3.2 of the proposed BPM provisions that were attached to the draft BPM PRR.) This would provide an opportunity for resources not benefitting from participation in PIRP to reduce any financial hardship that might result from the need to install additional equipment by sharing the costs of the equipment.

The ISO wishes to point out that the implementation of these expanded forecasting and telemetry requirements is not dependent on any substantive revision to the tariff. Consequently, the ISO has proposed to make the BPM revisions to implement these requirements effective independent of the Commission's action on the proposed tariff revisions. The ISO has also proposed to make the first set of limitations described above effective with the BPM revisions for the expanded requirements. However, the second set of limitations – providing the opportunity for sharing agreements among non-PIRP participants – is only relevant if the Commission accepts the proposed tariff revisions, and the ISO does not propose to implement them until the Commission acts on the tariff filing.

7. Question. *Page 6 of the CAISO's 2008 Root Cause Study states that:*

> *The results demonstrate that the majority, almost 100% of the failures occurred due to telemetry equipment failures and unreported outages. In particular, based on further investigation with site engineers, the CAISO concluded that the* ***primary reason*** *for errant data during telemetry outages is the absence of an independent or backup power supply for the telemetry equipment including the DPG [Data Processing Gateway]. A majority of wind parks power their telemetry and meteorological equipment by back feeding from the transmission lines, or directly from a feeder line connected to a group of wind generators. Accordingly, when a site is forced into an outage resulting from utility work on the transmission lines, the DPG and other equipment lose power. Similarly, if the telemetry equipment is powered by a the wind turbine feeder line, when the line is forced off, due to maintenance or other equipment problems, then all the associated telemetry equipment using the feeder line also fails and the site is not able to provide real time telemetry to the FSP.*[24]

a) How does the CAISO's instant proposal address what it found to be the primary reason for the errant or poor quality data? b) Please provide supporting data from the study.

Response.

(a) As explained in the November 25 Tariff Amendment, a proposed request by the ISO to revise the BPMs to implement the updated requirements for Eligible Intermittent Resources was under development late last year and would be posted on the ISO's website.[25] The ISO's proposed revisions regarding those requirements are found in BPM PRR 132 (also discussed in Response #6, above), which includes revisions to Appendix A to the BPM for Market Operations to address the primary reason for the errant or poor quality data discussed in the 2008 Root Cause Study.[26] Specifically, the proposed revisions, which are to be contained in new Section A.14.2 (entitled "Wind Generator Forecasting and Communication Equipment Requirements") of Appendix A to the BPM, state:

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24 2008 Root Cause Study at 6.

25 Transmittal Letter for November 25 Tariff Amendment at 5 n.6.

26 The current version of those revisions are contained in the document entitled "Proposed PIRP BPM lang 2 12 10 final redline".

> **A.14.2.4 Data Collecting Device Backup Power**
>
> Many sites provide the primary power for the meteorological stations and DPGs by either back feeding from the transmission line or directly from the wind turbine feeders. Each meteorological station and DPG must have a backup power source that is independent of the primary power source for the station (e.g., station power, battery or solar panel). The backup power source must provide power until primary power is restored. The same backup source can be used for both meteorological stations.

These BPM revisions are contained in the revised document associated with BPM PRR 132 entitled "Document: Proposed PIRP BPM lang 2_12_10 final redline.doc"[27] and are provided in Attachment G hereto. BPM PRR 132 also explains that the BPM changes that include the above-quoted language have been forwarded to ISO senior management for review and approval.[28]

The ISO's November 25 Tariff Amendment would apply the requirements of Appendix A, Section A.14.2.4 to all Eligible Intermittent Resources rather than only those that have elected to participate in PIRP. As such, the November 25 Tariff Amendment does establish a backup power supply requirement for all Eligible Intermittent Resources and therefore does address the primary reason for the errant or poor quality data discussed in that portion of the 2008 Rate Cause Study.

(b) A computer disk containing the supporting data for the 2008 Root Cause Study is provided with the instant filing. Because this supporting data includes commercially sensitive information about a number of market participants, the ISO is requesting privileged treatment of this data.

II. Request for Privileged Treatment

Pursuant to Section 388.112 of the Commission's regulations,[29] the ISO respectfully requests that the Commission designate as privileged Attachments D and F to the instant filing and the computer disk provided in response to Question 7(b). All of

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27 That revised document is posted on the ISO website at the following link: https://bpm.caiso.com/bpm/prr/show/PRR000000000132.

28 *See* document associated with BPM PRR 132 entitled "Final Decision now approved and listed in the available documents. {DEC000000000130} Summary: Forward," available on the ISO's website at https://bpm.caiso.com/bpm/prr/show/PRR000000000132.

29 18 C.F.R. § 388.112.

these materials contain commercially sensitive information regarding various market participants. Therefore, the materials should be withheld from public disclosure. These materials are provided in a separate volume along with this filing as required by Section 388.112 of the Commission's regulations.

III. Request for Modified Effective Date

In the November 25 Tariff Amendment, the ISO requested that the tariff revisions contained therein be made effective as of February 1, 2010, which the ISO noted was the first day of the month more than 61 days following the date the tariff amendment was filed.[30] Because it is no longer possible for the tariff revisions contained in the November 25 Tariff Amendment to be made effective as of February 1, 2010, the ISO hereby modifies its requested effective date. The ISO now requests that the Commission make the tariff revisions contained in the November 25 Tariff Amendment (other than those discussed in the next paragraph) effective as of May 1, 2010, which is the first day of the month that is 61 or more days (in fact, exactly 61 days) after the date of filing of the instant response to the January 29 Letter. This requested effective date will permit the ISO to implement the requested tariff revisions in a manner that is best accommodated by its systems, while providing the ISO some time to account for any changes the Commission may order to the proposed tariff revisions. For these reasons, the Commission should grant the ISO's requested May 1, 2010 effective date.

In the December 31 Answer (at 8), the ISO explained that it believes it is appropriate to provide additional time for the automation of forced outage reporting systems in order to minimize the burden of compliance with the ISO's proposed expanded forced outage reporting requirements. The ISO stated that, as it prefers to have the new requirements take effect on the first day of the month, the ISO proposed that the Commission order that the effective date for the expanded forced outage reporting provisions in tariff sections 9.3.10.3 and 9.3.10.3.1 be April 1, 2010 (*i.e.*, two months after the requested February 1, 2010 effective date for most of the tariff revisions). The ISO continues to believe that additional time to comply with these requirements is appropriate. Therefore, consistent with the ISO's requested modification of the effective date for most of the tariff revisions contained in the November 25 Tariff Amendment, the ISO now also requests that the Commission make the expanded forced outage reporting provisions in tariff sections 9.3.10.3 and 9.3.10.3.1 effective as of July 1, 2010, *i.e.*, two months after May 1.

IV. Attachments

The following attachments support the instant filing:

Attachment A Declaration of James Blatchford on behalf of the ISO

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[30] Transmittal Letter for November 25 Tariff Amendment at 9.

Attachment B	Declaration of Clyde Loutan on behalf of the ISO
Attachment C	Document entitled *Integration of Renewable Resources* (Nov. 2007)
Attachment D	Document entitled *CAISO PIRP Wind Power Production Forecast Performance 2007* (Apr. 2008) – submitted with request for privileged treatment
Attachment E	Comment provided by VIASYN in ISO stakeholder process
Attachment F	Data specific to market participants regarding costs of meteorological towers costs and cost of installing required communications equipment – submitted with request for privileged treatment
Attachment G	New Section A.14.2.4 of Appendix A to the BPM for Market Operations

In addition, as explained above, the ISO is providing, with a request for privileged treatment, a computer disk containing the supporting data for the 2008 Root Cause Study.

V. Communications

Communications regarding this filing should be addressed to the same individuals that were designated to receive service in the November 24 Tariff Amendment, namely:

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VI. Service

The ISO has served copies of the public version of the instant filing, including all attachments thereto, upon all parties in the above-referenced proceeding. In addition, the ISO is posting the public version of this filing and all attachments thereto on its website.

If you have any further questions or comments, please feel free to contact the undersigned.

Respectfully submitted,

Bradley Miliauskas

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ATTACHMENT A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER10-319-___**

DECLARATION OF JAMES BLATCHFORD ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. Introduction

Q. Please state your name and business address.

A. My name is James Blatchford. My business address is 151 Blue Ravine Road, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am employed as Senior Stakeholder Engagement and Policy Specialist, Stakeholder and Regulatory Affairs, of the California Independent System Operator Corporation ("ISO"). I am responsible for integrating the ISO's Participating Intermittent Resource Program ("PIRP") into the ISO's Integration of Renewable Resources Program ("IRRP") in support of the State of California Renewables Portfolio Standard ("RPS"). The ISO is working with Participating Transmission Owners, the California Energy Commission ("CEC"), the California Public Utilities Commission ("CPUC"), industry experts, adjacent balancing authority areas, and owners/developers of renewable resources to identify integration issues and solutions for the integration of large amounts of renewable resources into the ISO balancing authority area. I also have responsibility for ensuring the use of the latest wind and solar forecasting science and techniques within the ISO market system to reduce conventional carbon-based generation and dispatch costs.

Q. **Please describe your professional and educational background.**

A. I have over thirty years of project management experience in high-technology areas within the utilities, aerospace, and computer integrated chip manufacturing industries. I have worked for the ISO for more than nine years and have spent eight of those years focusing on issues involving renewable resources. I received a Bachelor of Science degree in Computer Information Systems from Chapman University, and a Master of Science degree in Electronic Commerce from National University.

Q. **Please describe your involvement in the process that led to the preparation and submission of the tariff amendment submitted in this proceeding on November 25, 2009.**

A. Under California's RPS legislation, utilities in the state are required to meet 20 percent of their supply needs with renewable generation by 2010, although the California Public Utilities Commission (CPUC) has subsequently stated that 2013 is likely a more realistic compliance date. In addition, the Governor of California has issued an executive order that sets a target for renewable energy resources to supply 33 percent of the power to California by 2020. A large amount of the renewable generation needed to meet these standards will be wind and solar generators, resources that are characterized by their intermittent or variable output.

As part of the IRRP, I oversaw a number of related efforts to examine the operational and other impacts of integrating large amounts of intermittent generation into the ISO's resource portfolio. These efforts examined the role and value of forecasting in addressing operational challenges created by large amounts of intermittent resources. These efforts also focused on ways to improve system forecasts of intermittent resources, including better data on local meteorological conditions and individual unit outages. These efforts led the ISO to develop, in a stakeholder process lasting approximately one year, and establish, new standards and requirements for all future intermittent resources connecting to the ISO controlled grid (in other words, all Eligible Intermittent Resources). The tariff amendment submitted to the Federal Energy Regulatory Commission on November 25, 2009 was intended to implement these new standards and requirements.

Q. What is the purpose of your declaration in this proceeding?

A. I will discuss several matters in my declaration. First, I will explain the characteristics of the intermittent resources that supply power to the ISO balancing authority area. I will then discuss the anticipated large increase in the supply of intermittent resources that will soon occur. Then I will discuss the consequences that the increase in the supply of power from intermittent resources will have on ISO operations. Lastly, I will explain why the tariff changes that the ISO proposes in this proceeding are appropriate to address the consequences of the power increase resulting from the coming addition of intermittent resources.

II. Characteristics of Intermittent Resources Supplying Power to the ISO Balancing Authority Area

Q. What types of intermittent resources supply power to the ISO balancing authority area?

A. Under Appendix A to the ISO tariff, Eligible Intermittent Resources are Generating Units whose primary source of power is either wind, solar energy, or hydroelectric potential derived from small conduit water distribution facilities that do not have storage capability. In this declaration, I will focus on wind- and solar-powered Eligible Intermittent Resources subject to an executed Participating Generator Agreement ("PGA") or a Qualifying Facility Participating Generator Agreement ("QF PGA"). The ISO has proposed in this proceeding to revise the definition of an Eligible Intermittent Resource in a compliance filing to exclude small conduit water distribution facilities without storage capability, and has proposed to not apply the tariff revisions proposed in this proceeding to intermittent resources that are not subject to a PGA or QF PGA. Generally, any reference to intermittent resources therefore encompasses wind and solar resources subject to a PGA or QF PGA.

A subset of Eligible Intermittent Resources are Participating Intermittent Resources, which are Eligible Intermittent Resources that elect to participate in the ISO market pursuant to PIRP.

Q. What features do Participating Intermittent Resources and other Eligible Intermittent Resources have in common?

A. All Eligible Intermittent Resources, including Participating Intermittent Resources, are characterized by variable output, which arises because the power generated by those resources fluctuates based on the changing availability of their primary fuel sources (absent storage). Because of their inherent variability, all Eligible Intermittent Resources present operational challenges to the ISO that I will discuss below. Those operational challenges are largely the same for all Eligible Intermittent Resources in that PIRP, as described next, primarily provides alternative rules governing the financial settlement of Participating Intermittent Resources.

Q. What features distinguish Participating Intermittent Resources from other Eligible Intermittent Resources?

A. The most significant distinguishing feature is that Participating Intermittent Resources are treated differently from a financial standpoint than other Eligible Intermittent Resources. Each Participating Intermittent Resource is subject to different settlement rules than apply to other Eligible Intermittent Resources and is subject to additional scheduling requirements tied to those settlement rules. Specifically, Scheduling Coordinators for Participating Intermittent Resources are required to submit schedules that are consistent with an hourly energy forecast developed by a forecast services provider employed by the ISO. Participating Intermittent Resources also receive a reduction of exposure to charges for real-time imbalance energy charges. This reduction of exposure occurs due to netting – the Participating Intermittent Resource's real-time deviations are summed over the course of each month and the net result is settled at the monthly weighted average real-time locational marginal price ("LMP") at the Participating Intermittent Resource's node. By contrast, Eligible Intermittent Resources that are not Participating Intermittent

Resources are not required to submit schedules consistent with energy forecasts and are not able to use netting to reduce their exposure to real-time imbalance energy charges.

Historically, Participating Intermittent Resources also have been subject to certain telemetry and forecasting requirements that the ISO did not apply to Eligible Intermittent Resources that did not elect to participate in PIRP. As intermittent resources become a much greater percentage of the generation mix in California, however, the ISO has determined that system operational needs require the ISO to obtain a better forecast from all Eligible Intermittent Resources in the region, whether or not they elect to participate in PIRP.

III. Current and Future Amounts of Power Supplied to the ISO Balancing Authority Area by Eligible Intermittent Resources

Q. What amount of intermittent resource capacity is currently installed in the ISO Balancing Authority Area?

A. Currently, there are approximately 3,500 MW of wind and solar generation in the ISO balancing authority area to serve a peak load of 50,000 MW.

Q. Are there any factors that are expected to cause an increase in the amount of power supplied to the ISO Balancing Authority Area by Eligible Intermittent Resources in the future?

A. Yes. As a result of the California RPS requirements discussed above, the amount of power supplied to the ISO balancing authority area by wind- and solar-powered Eligible Intermittent Resources is expected to increase dramatically.

IV. Consequences of the Impending Increase in the Amount Power Supplied by Eligible Intermittent Resources

Q. Will the increase in the amount of power supply to the ISO balancing authority area by Eligible Intermittent Resources that you have discussed have an effect on ISO operations?

A. Yes, the increase will have a large effect on ISO operations, specifically on unit commitment and dispatch decisions.

Q. Please explain.

A. The ISO employs a forecast services provider that develops a day-ahead and an hourly energy forecast of the amount of real-time output that is expected to be provided by Participating Intermittent Resources. In anticipation of the greater level of intermittent resources on the system, the ISO is enhancing its operating practices and software systems to better incorporate this forecast information into dispatch and unit commitment decisions, including, but not limited to, the possibility of applying a more probabilistic approach. Therefore, the better the information on the expected real-time output of wind and solar generation, the better the forecast will be and thus the better or more efficient the ISO's dispatch and unit commitment decisions will be. Therefore, as a general matter, the better the forecast, the lower the quantity of regulation service and load-following capability that will be needed on the system to account for forecast error, as explained in the declaration of my colleague, Mr. Loutan.

As I have stated, the ISO anticipates that large amounts of new intermittent resources will supply power to the ISO balancing authority area in the future due to the RPS requirements. The addition of these new intermittent resources will magnify the importance of accurate forecasts and those forecasts on ISO operations. The ISO determined that it requires improved information on the expected real-time output of wind and solar generation in order to better accommodate the addition of the new intermittent resources. Improved information will permit the forecasts to be more accurate, which in turn will allow the ISO's systems and operators to make better unit commitment and dispatch decisions in advance of real-time. As noted above, can act to reduce the quantity of regulation service and load-following capability that must be carried on the system at account for forecast error. The ISO filed its tariff changes in this proceeding in order to require intermittent resources to provide the improved information.

Q. Can you provide you provide some examples how inaccurate forecasting of intermittent resources may impact ISO operations?

A. Yes. The ISO's Residual Unit Commitment ("RUC") procurement target may be adjusted based on the ISO's forecasted deliveries from Eligible Intermittent Resources. RUC operates to commit additional capacity to make up for any difference between the capacity committed by the integrated forward market and the capacity needed to reliably serve the ISO's forecast for the next day's demand. Since the total schedules in the day-ahead market may differ from the ISO's real-time forecast, including forecasted deliveries from Eligible Intermittent Resources in real-time, the ISO may account for this discrepancy by making either a supply-side adjustment when the scheduled quantity is less than the forecast or a demand-side adjustment when the scheduled quantity is greater than the forecast. An inaccurate forecast of likely Eligible Intermittent Resource output may, therefore, potentially lead to inefficient RUC outcomes.

Inaccurate forecasts of intermittent resources can also cause problems for system reliability. For example, if the forecast overstates the amount of power that will actually be available from intermittent resources in real-time, the ISO may have insufficient resources committed through the RUC or its Short-term Unit Commitment processes to meet the ISO's hourly demand. As intermittent resources become a larger and larger part of the ISO's generation mix, the risk to reliability posed by inaccurate forecasts of intermittent resource output will only increase.

Q. Do any studies indicate that a lack of accurate data, insufficiently granular forced outage reporting, or other inaccurate information can detrimentally affected forecasts of intermittent resource output?

A. Yes. In April 2008, the ISO issued a study of the performance of wind power production by Participating Intermittent Resources using 2007 data. In the study, AWS Truewind documented the data quality of the wind resources participating in PIRP. AWS Truewind then determined and compared the deviation of the actual generation to the forecasts and then correlated the data quality to the forecast accuracy. The study showed that the overall degradation of the mean absolute error for both next operating hour and next-day forecasts was about 20 percent relative to what could have been achieved if all intermittent resources considered in the study had provided data regarding power production, turbine availability, and meteorological data that was of a data quantity and quality similar to that provided by the best Participating Intermittent Resource data provider. One wind park considered in this study with numerous meteorological towers provided an excellent example of how good data quality and MW availability results in an above average forecast. The three other wind parks, one of which is adjacent to the park with multiple meteorological towers, considered in that study had limited data quality and quantity, and demonstrate the negative effect on forecast accuracy. This study is provided in Attachment D to the ISO's response in this proceeding.

Q. Is the ISO's focus on improving forecast accuracy consistent with industry studies considering the operational impacts of integrating large amounts of renewable resources?

A. Yes. The North American Electric Reliability Corporation ("NERC") has established an Integration of Variable Generation Task Force. Work by this task force is ongoing. In April 2009, this task force issued a report entitled "Accommodating High Levels of Variable Generation." One of the primary conclusions and recommendations of this report focused on the need for system operators to improve forecasting of variable generation (a.k.a. intermittent resources):

> Enhanced measurement and forecasting of variable generation output is needed to ensure bulk power system reliability, in both the real-time operating and long-term planning horizons. Significant progress has been made in this field over the past decade, though considerations for each balancing authority will differ. Forecasting techniques must be incorporated into real-time operating practices as well as day-to-day operational planning, and consistent and accurate assessment of variable generation availability to serve peak demand is needed in longer-term system planning. High-quality data is needed in all of these areas and must be integrated into existing practices and software. The electric industry is also encouraged to pursue research and development in these areas.

This report can be found on NERC's website at:

http://www.nerc.com/files/IVGTF_Report_041609.pdf.

In addition, two studies issued in September 2009 by the National Renewable Energy Laboratory ("NREL") included findings that emphasized the importance of accurate forecasts of output from wind-powered intermittent resources. In one of these studies, NREL found that "Forecasts are critical. There are significant variations in impact for the same wind variability with different forecasts." In the other study, NREL concluded that "[e]merging conclusions indicate that 20% wind energy penetration can be managed, but the role of wind forecasting is important to meet this objective." Thus, multiple studies support the ISO's need for forecasts of intermittent resource output that are as accurate as possible. These two studies can be found on NREL's website at http://www.nrel.gov/wind/systemsintegration/pdfs/2009/lew_grid_operations.pdf and http://www.nrel.gov/wind/systemsintegration/pdfs/2009/milligan_large_integration_studies.pdf.

V. <u>The Tariff Changes the ISO Proposes in this Proceeding</u>

Q. What measures does the ISO propose in this proceeding to improve the accuracy of its forecasts of deliveries from Eligible Intermittent Resources?

A. There are two such measures. The first is a requirement that all Eligible Intermittent Resources (except those that the ISO may exempt from the requirement based on resource-specific considerations) install specified forecasting and telemetry equipment and communicate relevant data (*e.g.*, meteorological data) to the ISO. Currently, this obligation applies only to Participating Intermittent Resources. The second measure the

ISO proposes is to reduce the threshold for reporting a forced outage of an Eligible Intermittent Resource with a total capacity of greater than 10 MW from the current outage capacity level of 10 MW to 1 MW.

Q. How will these measures improve the forecasts for Eligible Intermittent Resources?

A. As I have explained, the inherent variability of all Eligible Intermittent Resources can detrimentally affect the accuracy of forecasted power supply. Although a certain level of uncertainty associated with intermittent resource forecasts can never be eliminated, it can and should be minimized to the extent practicable. This is especially true given that intermittent resources will become an ever-larger part of the ISO's resource mix. The installation of specified forecasting and telemetry equipment, the communication of relevant data to the ISO, and the introduction of more granular outage reporting will allow the ISO's forecast service provider to make a much more detailed forecast of the expected output of wind and solar resources. The more detailed forecast, in turn, will improve the ISO's unit commitment and dispatch decisions and will reduce the ISO's costs of procuring regulation and load-following services associated with intermittent resources.

Q. How did the ISO determine it is appropriate for intermittent resources to report forced outages at the 1 MW threshold rather than some other MW threshold?

A. There are several reasons why the ISO determined that the 1 MW threshold is appropriate. One MW is the typical minimum size of a single wind turbine in new wind farms being constructed in the ISO balancing authority area. Thus, a 1 MW outage reporting requirement will provide the ISO with information when even a single turbine at a wind farm is out of service. One MW is also the minimum size of a resource that the ISO's systems can recognize as an "intermittent resource," regardless of whether that resource is a wind or solar resource. The existing 10 MW outage reporting requirement resulted in many individual turbine outages going unreported to the ISO, significantly contributing to forecast errors. In order to reduce these errors, the ISO concluded that it was appropriate to reduce the outage reporting threshold for intermittent resources by a single order of magnitude, *i.e.*, from 10 MW to 1 MW.

Q. Is it appropriate to apply the measures the ISO proposes to all Eligible Intermittent Resources?

A. Yes. Because of their inherent variability, all Eligible Intermittent Resources present the same operational challenges to the ISO – namely, challenges related to unit commitment and dispatch and the procurement of regulation and load-following services. Therefore, it is appropriate to apply to the measures that the ISO proposes to address those operational challenges to all Eligible Intermittent Resources. And as more intermittent resources are integrated into the electric system operated by the ISO due to the implementation of the RPS requirements, the need to apply those measures to all Eligible Intermittent Resources will be magnified.

Q. Have most of these Eligible Intermittent Resources joined PIRP and thus are Participating Intermittent Resources?

A. Yes. There are currently only four wind or solar generators with a total capacity of approximately 7.1 MW that are Eligible Intermittent Resources subject to a PGA or QF

PGA and that have not yet joined PIRP. Some of these resources are newer resources and may elect to join PIRP once they have greater experience in the ISO's markets. Thus the category of Eligible Intermittent Resources that do not participate in PIRP is very small.

Q. Could the failure to apply the tariff changes proposed in this proceeding adversely affect the ability of the ISO to respond to the operational challenges created by increased levels of intermittent resources?

A. Yes. The ISO expects that most owners of Eligible Intermittent Resources that connect to the ISO controlled grid in the future will elect to participate in PIRP. The ISO cannot be certain, however, that this will occur. If only those resources that voluntarily participate in PIRP are subject to enhanced telemetry, forecasting, and outage reporting requirements, the ISO and its forecast service provider may not have access to critical data from a number – potentially a large number – of intermittent resources. This could lead to operator commitment and dispatch decisions based on inaccurate system forecasts for intermittent resources, the failure to procure sufficient resources through the RUC process, and increased costs to ISO customers due to the need to procure additional regulation and load-following services.

Q. Will Eligible Intermittent Resources receive any benefits they do not receive today once they are subject to enhanced telemetry, forecasting, and outage reporting requirements and are required to pay the associated forecast fee?

A. Yes. Today, Participating Intermittent Resources receive a resource-specific forecast from the ISO's forecast services provider that reflects the data for that resource provided to the ISO. These resource-specific forecasts in the aggregate are primary inputs into the system-wide forecast used by the ISO. Once the ISO's proposed tariff revisions go into effect, Eligible Intermittent Resources will also receive these resource-specific forecasts.

Q. Does this conclude your declaration?

A. Yes, it does.

ATTACHMENT B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER10-319-___**

DECLARATION OF CLYDE LOUTAN ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Clyde Loutan. My business address is 151 Blue Ravine Road, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am a Senior Advisor employed as the project lead for renewable generation resource integration at the California Independent System Operator Corporation ("ISO"). I currently focus on system operation performance-related issues, including issues related to renewable generation (which is also sometimes called intermittent or variable generation). In addition, I am a part of the Western Electricity Coordinating Council ("WECC") performance workgroup. This workgroup identifies areas where improved grid operating performance is required, and coordinates performance improvement activities with all WECC members in their individual and combined efforts to comply with the operating policies, guidelines, regional criteria, and standards of both WECC and the North American Electric Reliability Corporation ("NERC"). I also serve on the

NERC Variable Generation Integration and the NERC Reliability Based Control Standards workgroups developing national operating standards.

Q. Please describe your professional and educational background.

A. I worked for fourteen years at Pacific Gas and Electric Company, where I provided services in areas such as real-time system operations, transmission planning, and high voltage protection. I then consulted with Ecco International, Inc. for a year. After joining the ISO in 2000, I acted as lead engineer in charge of investigating the root cause of the California blackouts in 2000 and 2001. I also led the team that integrated the first pseudo tie to operate within the ISO market construct. I received a Bachelor of Science degree and a Master of Science degree in Electrical Engineering from Howard University.

Q. Please describe your involvement in the process that led to the preparation and submission of the tariff amendment submitted in this proceeding on November 25, 2009.

A. As discussed in the separate Declaration of James Blatchford, the tariff changes the ISO proposes in this proceeding are intended to address the consequences of the increase in power supply in the ISO balancing authority area that will result from the addition of significantly more intermittent or variable resources due to the enactment of Renewable Portfolio Standard ("RPS") legislation in California. During the development of the tariff changes, I analyzed, and had a central part in preparing ISO studies on, the effects on ISO system operation performance of integrating these additional intermittent resources into the ISO's generation mix.

Q. What is the purpose of your declaration in this proceeding?

A. I will discuss the effects on reliability that the ISO expects will occur due to its expected need to procure additional load-following services associated with wind-powered and solar-powered intermittent resources. The ISO has conducted an analysis of the effects and has recently updated its analysis. I will provide the ISO's updated analysis and explain its results and implications for system efficiency.

Consistent with the ISO's proposed tariff revisions in this proceeding, my Declaration specifically focuses on wind- and solar-powered Eligible Intermittent Resources (as defined in the ISO tariff) subject to an executed Participating Generator Agreement ("PGA") or a Qualifying Facility Participating Generator Agreement ("QF PGA").

II. Effects of Procuring Additional Load-Following Services Associated with Intermittent Resources

Q. What effect is the RPS legislation expected to have on the amount of intermittent resources in the ISO balancing authority area?

A. Currently, there are approximately 3,500 MW of wind and solar generation in the ISO balancing authority area to serve a peak load of approximately 50,000 MW. The state's renewable portfolio standard (RPS) legislation requires utilities in California to meet 20 percent of their supply needs using renewable generation by the end of 2010. However, the California Public Utilities Commission (CPUC) has stated that a more realistic compliance date is likely 2013-14. Further, the Governor of California has issued an executive order that targets renewable energy resources to supply 33 percent of the power to California by 2020. Therefore, the increase in intermittent resources in California due to the RPS legislation is likely to be significant.

Q. Please provide an overview of the effects that the increase in power supply resulting from the addition of intermittent resources in California will have on ISO system operations.

A. The addition of intermittent resources in California will have multiple effects on ISO system operations. One of the most important effects from the perspective of the tariff changes proposed in this proceeding is the additional regulation and load-following requirements that must be accounted for in the ISO's dispatch and unit commitment decisions, which is a subject that Mr. Blatchford addresses in his declaration. The need for additional regulation and load-following capability on the ISO system is likely to affect the overall costs of providing such services.

Q. What is regulation?

A. Regulation is generating capacity under automatic generation control that is used to continuously balance supply (including interchange schedules) and real-time load on the ISO system. Regulation is dispatched every four seconds by the ISO's energy management system. However, the quantity of regulation capacity must be capable of adequately meeting deviations that occur within the five-minute periods between each economic dispatch of energy through the ISO's real-time market software applications.

Regulation only accounts for imbalances within these five-minute periods. Regulation can be either in an upward or a downward direction, depending on whether generation is required to increase production or decrease production to meet fluctuations in load. The ISO procures regulation services to satisfy applicable requirements through the ISO ancillary services markets.

Q. What is load-following?

A. Load-following is the dispatch of energy in the real-time market to address longer-term imbalances that are not addressed by regulation. Load-following is automatically conducted by the ISO market applications using a look-ahead resource commitment function and a five-minute economic dispatch of energy. The deviations that create a load-following requirement stem from the transition from an average hourly schedule (*i.e.*, a fixed level of output for sixty minutes) to actual dispatch on a five-minute basis in order to account for changes in load, changes in generation and transmission system conditions (*e.g.*, outages), and errors in forecasting power supply. Like regulation, load-following can be either in an upward or a downward direction, depending on whether generation is required to increase production or decrease production to meet the fluctuation in load. The ISO generally obtains load-following services by dispatching resources that have submitted bids to provide energy in the real-time market.

Q. In what ways do wind- and solar-powered intermittent resources affect the procurement of regulation and load-following services through the ISO markets?

A. There are two ways that wind and solar generation contribute to the quantity of regulation and load-following services that must be procured by the ISO. First, a certain portion of the regulation and load-following services that the ISO must procure are attributable to the inherent variability of the power output of wind and solar resources, which is due to the variability of the supply of their main fuel source. All electric power systems must balance constantly changing demand with available supply. Utility power systems, therefore, historically have been designed to manage a certain degree of demand volatility and supply unpredictability through reliance on forward scheduling, real-time economic dispatch, and procurement of ancillary services.

Second, an additional incremental amount of regulation and load-following services are attributable to forecast error, *i.e.*, flaws in the ISO's current forecast of intermittent resource output. While forecast error occurs for load as well as for intermittent resources within the five-minute period balanced by regulation, the majority of the deviation between supply and demand within the five-minute period can be attributed to the variability of load and variable wind and solar resources, rather than forecast uncertainty. The same is not true for the longer-term period addressed by load-following. Accordingly, the inherent variability and significantly greater unpredictability of the output from wind and solar resources necessarily increases the aggregate variability that must be managed by the electrical grid both through regulation and load-following, but especially through load-following capability. The focus of this declaration therefore is on the impact on load-following services attributable to forecast errors.

Q. Please describe the analyses the ISO has conducted regarding the procurement of regulation and load-following services through the ISO markets.

A. The ISO's original analysis, and the methodology for that analysis, were set forth in an ISO report entitled *Integration of Renewable Resources*, published in November 2007 and provided as Attachment C to the ISO's response in this proceeding. I was one of the principal investigators involved in analyzing the data covered in that report and writing that report. As part of the ISO's efforts to ensure the reliable integration of high levels of renewable resources due to the RPS legislation, the ISO recently updated its prior analysis quantifying the regulation and load-following requirements needed to manage the expected hourly and intra-hour system variability, including the contribution from forecast uncertainty, expected under a 20 percent RPS requirement. The update was performed, in part, to account for effects on system variability of solar thermal and solar photovoltaic technologies.

Q. What were the results of the ISO's updated analysis?

A. Table 1, below, depicts the results of the updated analysis. The analysis examines a 20 percent RPS base case for the year 2012. The ISO used a conservative estimated date of 2012 for when investor-owned utilities within the ISO balancing authority area will achieve the 20 percent RPS mandate. For the ISO study, meeting the 20 percent RPS target in 2012 is accomplished through the introduction of a combination of new in-state geothermal, small hydroelectric, biomass, biogas, and wind and solar resources, as well as assumed renewable imports. The base case assumes 6,700 MW of wind power and 2,200 MW of solar power within California. The load-following component of the analysis was performed only for wind and solar power given that the other renewable technologies I mentioned have little variability and unpredictability and therefore have significantly less impact on the ISO's need for load-following capability.

In order to isolate the effect of intermittent wind and solar resource forecast error from the effects intermittent resource variability and load variability and forecast error, the ISO ran a number of simulations. All cases assume a load forecast error of one standard deviation between 600 MW to 900 MW based on historical data for different seasons. For the wind cases, separate simulations were run with load error and (i) without wind error and (ii) with a wind hour-ahead forecast error of one standard deviation between 7 percent and 9 percent of installed capacity, again depending on the season. This is consistent with the observed errors for the ISO's current hour-ahead forecast of production from wind generation. Similarly, separate simulations were run with load error and (i) without solar forecast error and (ii) with solar forecast error. The hour-ahead forecast errors for solar power ranged between 5 percent and 20 percent depending on whether the operating day was expected to be sunny or cloudy. This range of solar forecasting error was based on research of other systems, mainly in Europe, that have higher penetration levels and history with solar resources.

Table 1

		Load-Following Up	Load-Following Down
Season	**Forecast Error Term**	**Average (MW)**	**Average (MW)**
	Load with error, Wind without error	2,001	(1,978)
	Load with error, Wind with error	2,628	(2,562)
Winter	Wind forecast error impact	627	(584)
	Load with error, Solar without error	2,002	(1,980)
	Load with error, Solar with error	2,079	(2,031)

Winter	Solar forecast error impact	77	(50)
	Load with error, Wind without error	1,872	(1,858)
	Load with error, Wind with error	2,815	(2,747)
Spring	Wind forecast error impact	943	(889)
	Load with error, Solar without error	1,855	(1,851)
	Load with error, Solar with error	1,928	(1,915)
Spring	Solar forecast error impact	73	(64)
	Load with error, Wind without error	2,747	(2,747)
	Load with error, Wind with error	3,399	(3,537)
Summer	Wind forecast error impact	652	(790)
	Load with error, Solar without error	2,719	(2,720)
	Load with error, Solar with error	2,765	(2,756)
Summer	Solar forecast error impact	46	(35)
	Load with error, Wind without error	2,129	(2,127)
	Load with error, Wind with error	2,812	(2,861)
Fall	Wind forecast error impact	683	(733)
	Load with error, Solar without error	2,128	(2,110)
	Load with error, Solar with error	2,220	(2,164)
	Solar forecast error impact	92	(54)

Q. What conclusions do you reach based on the results of the ISO's updated analysis?

A. The results shown in Table 1 demonstrate that forecast error for renewable resources can have a significant impact on the amount of capacity that must be available to ramp within any particular hour to balance supply with load. Again, this supply must be able to move not only to account for the variation and forecast error in demand, but also to account for the variation and uncertainty in production inherent in solar and wind resources (assuming no power storage capability).

For example, Table 1 shows that, for the spring, the average impact of wind forecast error on load-following requirements is to require an additional 943 MW for load-following up and an additional 889 MW for load-following down. Therefore, for the spring, wind forecast error constitutes approximately 33 percent of load-following up and load-following down requirements.

The impact on load-following requirements from the assumed quantity of solar resources is more modest on average during the spring. However, solar resources, particularly photovoltaic resources, demonstrate significant output fluctuation within the hour due to transient cloud cover. Since the ISO, as a system operator, will be required to maintain reliability not only through average solar variability, but other high-probability events, the likely affect of solar resources on load-following capability will be greater than the average. The same is also true for wind resources.

Q. What potential effect does the forecast error shown in the ISO's updated analysis have on the costs of load-following service?

A. An increase in load-following requirements due to forecast error will likely impose costs on the system. As a general matter, the increase in costs has two sources. First, the more the system fluctuates, the more the system operator is required to have capacity available to convert the capacity to energy as needed to maintain the balance between supply and load. This may lead to the commitment or reservation of less efficient units than would otherwise be required to ensure the balance of more predictable and stable net load. Second, load-following may require the dispatched resources to move from their most efficient operating point to a less efficient operating point. Both of these types of circumstances can arise from forecast error and increase the costs of securing load-following capability on the system.

Q. Does inaccurate forecasting of required load-following capability have detrimental operational effects other than effects on cost?

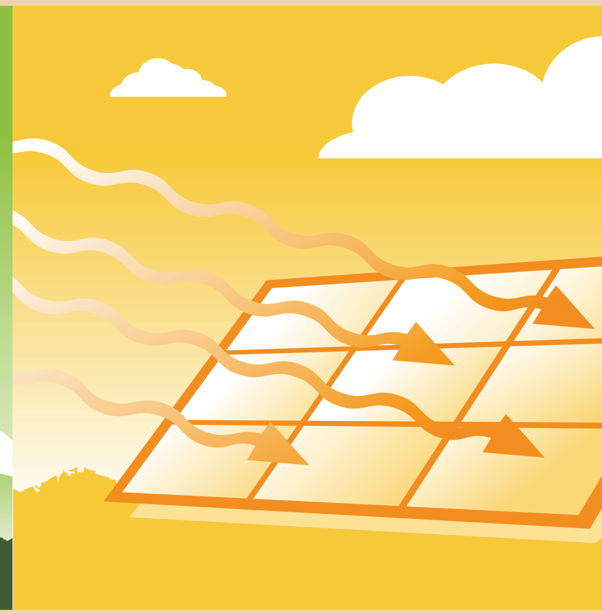
A. Yes. Inaccurate forecasting of required load-following services can cause difficulties for system reliability. Reliability problems can occur when an erroneous forecast either underestimates or overestimates the amount of load-following service that will be available. In the case of an underestimate, if the system operator is required to commit additional capacity at minimum load to be ready to make up for a shortfall in supply due an inaccurate prediction of expected renewable output, that will increase the possibility of there being too much generation on the system during low load periods, when wind power tends to be produced at its highest level. The operational and market consequences of over-generation include, but are not limited to, acceleration in system frequency, violation of control performance standards established by NERC, and an increase in excess energy flows to neighboring balancing authority areas as inadvertent energy, which can cause control performance problems for the receiving balancing authority areas. In the case of an overestimate, insufficient load-following capacity can result in a need to convert contingency resources to energy in order to satisfy load requirements or, at worst, an inability to serve load. Such a suboptimal result will have detrimental effects on system reliability.

Q. Does this conclude your declaration?

A. Yes, it does.

California ISO
Your Link to Power

California Independent System Operator



Integration of Renewable Resources

November 2007

Transmission and operating issues
and recommendations for integrating
renewable resources on the California ISO-controlled Grid

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The California ISO also wishes to acknowledge the many reviewers of the report for their valuable comments and suggestions.

The California Independent System Operator Corporation (California ISO) is a not-for-profit public benefit corporation formed in 1997 when the state restructured its electricity industry. It is the impartial link between power plants and the utilities and load-serving entities that provide electricity to almost 80 percent of California consumers, about 30 million people. The California ISO is responsible for the operation of 25,526 circuit-miles of long-distance, high voltage power lines that deliver electricity throughout most of California (California Grid) and between adjacent balancing authorities, neighboring states, Canada and northern Mexico. In 2006, the California ISO delivered 249.2 million megawatts hours of electricity and had a peak demand of 50,270 megawatts. The California ISO's principle objective is to ensure the reliability of the California Grid, while fostering a low-cost wholesale marketplace for electrical generation and related services in California. The California ISO operates pursuant to its Tariff filed with the Federal Energy Regulatory Commission. A five-member Board of Governors oversees the California ISO. Members are appointed by the governor, with consideration of recommendations from stakeholders, and are confirmed by the California State Senate.

Letter from the CEO

Current policies demonstrate that California is at the forefront of advancing renewable resource development. In the next few years, the state requires that electricity providers serve 20 percent of their retail load from renewable resources. Statewide, greenhouse gas emissions will also be reduced to 1990 levels by 2020. At the same time, California recognizes the importance of maintaining reliable electric service for consumers, which is primarily the responsibility of the California Independent System Operator Corporation (California ISO).

Consistent with that responsibility, the Renewables Portfolio Standard (RPS) and other environmental policies, the California ISO is proud to assist in meeting the state's objectives. The California ISO has taken several important programmatic steps related to transmission interconnections for remote resources such as renewables, market policies to facilitate successful integration of renewable resources, and enhancement of demand response opportunities consistent with state and federal priorities. These policies, however, have not addressed the reliability issues associated with the large increase in intermittent renewable generation that is expected in the next several years.

Earlier this year, the California ISO conducted an engineering study to assess the feasibility of maintaining reliable and high-quality electric service under the 20 percent RPS, with an understanding of where to focus ongoing analytic and implementation efforts. The "Integration of Renewable Resources" describes the California ISO's analytic approach to the issue, the conclusions of the related engineering studies, and the recommendations for achieving successful implementation of the state's 20 percent RPS. It is important to note what this study does not address the more challenging higher RPS targets. Higher targets are expected to present significantly greater operating challenges that cannot be evaluated by a simple straight line extrapolation from this study's conclusions.

The good news is that this study shows the feasibility of maintaining reliable electric service with the expected level of intermittent renewable resources associated with the current 20 percent RPS, *provided* that existing generation remains available to provide back-up generation and essential reliability services. The cautionary news is the "*provided*" part of our conclusion. Regulatory actions under active consideration threaten the economic viability of much of this essential generation. Moreover, current regulatory policies assigning high on-peak availability factors to intermittent generation will eliminate the theoretical — but not the real — need for the essential generation currently provided by existing power plants, and regulators may be unwilling to support sufficient forward procurement of generation. Furthermore, the model used for this study is based on the technical specifications and capabilities of the generation fleet, but does not reflect contractual or other regulatory constraints that are not known to the California ISO.

(continues next page)

The study shows the additional operating requirements and products needed to support the implementation of the 20 percent RPS. Further detailed engineering analysis, coordinated with generation and transmission owners, is needed to refine the assumptions, develop cost estimates and establish a full implementation plan. This is all currently being evaluated. We look forward to working with state policy makers, market participants, and other interested parties to ensure that we have a clear understanding of these and other critical issues in order to help policy makers find the most effective means of achieving important policy objectives in a way that is consistent with maintaining the reliability and quality of electric service in California.

Y. Mansour.

Yakout Mansour
California ISO President & CEO

Table of Contents

Executive Summary

California is a national leader in the development of renewable resources as it positions itself at the forefront of diversifying resources and reducing greenhouse gases. Currently, 6,000 megawatts (MWs) of installed renewable resources[1] including wind, solar, geothermal, biomass and small hydroelectric generation help to “green the grid”. These resources delivered more than 21 million megawatt hours of energy to California electric customers in 2006. This represents 11% of the total energy required to serve load in the California Independent System Operator Corporation (California ISO or CAISO) controlled Grid. To further develop environmentally friendly power, the state of California enacted a 20% Renewables Portfolio Standard (RPS). This statute requires each retail seller of energy to deliver sufficient energy from renewable resources to serve 20% of retail load by December 31, 2010. As a national leader in developing new initiatives to facilitate renewable development, California ISO initiated this study to help policy makers understand the unique requirements that are necessary to ensure that the operation and design of the transmission grid fully supports this renewable standard.

The California ISO has implemented two significant initiatives to facilitate the development and integration of renewable resources. First, in 2002, the California ISO put into place its Participating Intermittent Resource Program (PIRP) to better integrate wind generators into its Hour-Ahead markets. This program was a major breakthrough, in that it provides an opportunity to forecast and schedule energy production from intermittent generating resources. It enables wind generators to participate in the California ISO markets without being penalized for the inherent intermittency of wind generation. Second, in 2006 the California ISO led a new initiative with the FERC called the Remote Resource Interconnection Program. The program provides a mechanism for transmission upgrades that support renewable resources and permit construction of transmission to renewable energy resources that are located in areas that are remote from the existing transmission network.

This Report is another major initiative by the California ISO that addresses the transmission and operational impacts of interconnecting a major increase in the amount of renewable resources to the power grid. The report analyzes the issues, documents the results, and recommends steps that should be implemented to reliably integrate the planned intermittent resources. The Report builds on other integration studies, especially the CEC’s Intermittency Analysis Project Final Report published in July 2007, by adding significant new analysis and in-depth study of operational issues that can be expected from the increase in intermittent generating resources.

1 This figure of 6,000 MW and the analysis that follows from this figure only include energy production from renewable resources located in the California ISO controlled Grid, and therefore does not reflect renewable energy imported from adjacent balancing authorities. Figures provided by the CEC, CPUC and IOU’s may be higher than the amount stated above because such figures may also include the above referenced imports.

The California ISO is collaboratively working with load serving entities, state and federal regulators, industry experts, adjacent balancing authorities and the owners/developers of renewable resources to identify integration challenges and solutions. Because California has large quantities of renewable resources already on-line, a significant amount of historical data is available to accurately model and forecast future performance of the various types of renewable resources. Small hydroelectric, biomass and geothermal generation are more predictable resources, and the integration of these resources into both the markets and operations do not present significant problems. Concentrated solar is an intermittent resource, but the amount of generation from this resource is still small, so it does not result in significant integration issues. The amount of concentrated solar generation is expected to increase to more than 1,000 MW by the 20% RPS date but the amount of this resource will still be substantially less than the increase in the amount of wind generation and no serious operating issues are expected with solar generation.

New wind generating facilities are the fastest renewable resource to install and interconnect to the power grid. Wind generation, however, presents the largest operational challenges. Wind generation energy production is extremely variable, and in California, it often produces its highest energy output when the demand for power is at a low point. During some periods of the year, wind generation is hard to forecast because it does not follow a predictable day-to-day production pattern. Therefore, the focus of this Report is on the transmission and operating issues associated with the addition of more than 4,000 MW of new wind generation in the California ISO controlled Grid.

A majority of the new wind generation facilities will be built in the Tehachapi region in Southern California. During the summer months, the Tehachapi area has a pattern of maximum wind generation at night, a ramp down of energy production during the morning load pick up period, and a ramp up of generation in the evening. Integration of large amounts of wind generation is technically feasible, but there are transmission, operating and forecasting challenges. This Report discusses these integration issues and, more importantly, the proposed solutions and recommendations to facilitate renewables integration in California and the West.

Transmission Plan for Renewable Resources

The largest increase in renewable energy resources to meet the 20% RPS will be from wind generation, and the majority of this new wind generation will be installed in the Tehachapi Wind Resource area. The Tehachapi Transmission project was reviewed in detail to reassess the adequacy of the voltage controls, transient stability and post-transient voltage performance of the system. Standard transmission planning tools were used to assess the transient stability performance, voltage stability and reactive margin of the system with the addition of various levels of wind generation planned for the Tehachapi area. The objective was to assess the overall performance of the interconnected transmission system over a broad range of load, wind generation levels and wind turbine assumptions. The California ISO Regional Transmission Department and GE Energy Consulting performed a joint transmission analysis of the Tehachapi Transmission Project.

The primary objectives of the transmission system analysis were as follows:

1. Evaluate transient stability and post-transient voltage performance of the California ISO controlled Grid with increased levels of wind generation in the Tehachapi area.

2. Evaluate the post-transient voltage stability performance (Q-V analysis) of the California ISO-controlled Grid with increased levels of wind generation in the Tehachapi area.

3. Evaluate wind plant functional characteristics that are necessary to achieve acceptable static and dynamic performance of the California ISO controlled Grid.

4. Determine any needed improvements to the Grid to achieve acceptable performance with increased levels of wind generation and other renewable energy resources.

The modeling of the transmission system focused on a 20% renewable energy requirement, which includes a total of 4,200 MW of wind generation in the Tehachapi area. The model also included all the proposed new transmission facilities as described in Appendix G.

The Western Electricity Coordinating Council (WECC) 2010 Heavy Summer peak load and 2012 Light Spring load system conditions with 4,200 MW of total wind generation were modeled in the Tehachapi area. These base cases were selected because they represented extreme on-peak and off-peak operating conditions and the Heavy summer case had been used in previous joint studies with SCE.

For each seasonal condition, the following three wind generation scenarios were analyzed:

1. Full wind, where all Tehachapi area wind turbine generators are on-line, operating at rated MW

2. Low wind, where all Tehachapi area wind turbine generators are on-line, operating at 25% of rated MW

3. No wind, where all Tehachapi area wind turbine generators are off-line

For each scenario, the baseline analysis was performed assuming that all new wind plants would be Type 3[2] doubly fed wind turbine generators. The existing wind plants in the Tehachapi area were modeled as Type 1 conventional induction generators. A total of 25 contingencies (11 Category B and 14 Category C)[3] were simulated for each of the seasonal wind generation scenarios. Finally, several sensitivity studies were performed by varying the mix of wind turbine generator types based on the actual installations of new wind plants in the U.S. in 2006 (i.e., 10% Type 1 induction generator, 20% Type 3 doubly fed with power factor control, 50% Type 3 doubly fed with fast voltage regulation and 20% Type 4 full converter induction generators).

2 The four types of wind generators are described in detail in Appendix F. Briefly; Type 1 is a conventional fixed speed induction generator that operates synchronized to the power grid. It typically consumes VARS and does not meet Low Voltage Ride Through standards. Type 2 is similar to a Type 1 unit, but it uses a wound rotor induction generator with variable rotor resistance. Type 3 is a doubly-fed induction generator that is synchronized to the power grid, but uses a feedback loop that enables it to produces VARS. It meets Low Voltage Ride Through standards. Type 4 is similar to Type 3 and it has a full converter interface.

3 Category B is the loss of a single element, while Category C refers to events resulting in the loss of two or more (multiple) elements.

Conclusions from the Transmission Planning Study

The study concluded that the Tehachapi transmission plan is sound, and there are no serious transient stability or post-transient voltage stability problems. It does, however, point out the need to address some very important issues:

1. All new wind generation units must have the capability to meet the WECC requirements of ±0.95 power factor. This reactive capability is essential for adequate voltage control.

2. The proposed Tehachapi Transmission Project can support up to 4,200 MW of wind generation in the Tehachapi area, provided that the new wind plants adhere to the WECC Low Voltage Ride Through (LVRT) criteria.

   The existing Type 1 wind generators in Tehachapi do not meet this standard, and the studies show these units will trip off-line following a short circuit problem in the area. Type 3 and 4 wind generators meet the LVRT standard, and they will survive a short circuit event.

3. Dynamic reactive capability for all new wind generation facilities is essential. The California ISO should consider requiring that a minimum portion of the required power factor range be dynamic for each new wind park. Additional analyses will need to be performed to determine the minimum requirements for the dynamic range.

4. The California ISO's role is to ensure all new generation facilities meet the interconnection standards. Although the California ISO does not have the tariff authority to require all new wind generation to be Type 3 or Type 4 units, it can require that any new Type 1 or Type 2 units must have sufficient static and dynamic reactive resources to meet the interconnection standards.[4]

5. The bulk power system performed satisfactorily in both the transient and post-transient states with 4,200 MW total wind generating capacity in the Tehachapi area.

6. The frequency response of the Western Interconnection is not affected by the new wind generation within the California ISO controlled Grid.

7. A sensitivity analysis study shows that system performance is acceptable with either all Type 3 doubly fed wind turbine generators or with a mix of wind turbine generator technologies for the new wind plants. The pessimistic test scenario with 100% Type 1 wind plants with no dynamic reactive capability shows an unacceptable response. This suggests that wind plants with some dynamic reactive capability are necessary to ensure system stability. Therefore, if the dynamic reactive capability is not inherent in the wind turbine generator, it may need to be added to the wind plant.

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4 Clarifying statement added in response to comments from SCE. Generator Interconnection standards are specified in Section 25 of the California ISO Tariff and the Standard Large Generator Interconnection Procedures (LGIP) and the California ISO Tariff Appendix W.

8. Based on the transient stability study results, the bulk system (500 and 230 kV) shunt capacitors and Static VAR Compensation (SVC) for dynamic voltage support proposed in the Tehachapi Transmission Project appear to be conservative for the level of wind generation and the system conditions/outages considered in this study. The SVC sensitivity analysis shows that the proposed SVCs were not necessary to achieve acceptable transient stability performance with a likely mix of wind turbine generator technologies.

9. The sensitivity analysis shows that the proposed SVCs were not sufficient to achieve acceptable dynamic performance if all of the new wind plants were modeled with 100% Type 1 wind turbine generators and had no dynamic reactive capability. This is a pessimistic assumption since the majority of the new wind plants that were installed in the U.S. in 2006 were of Types 3 and 4, which are capable of providing dynamic reactive support.

10. With adequate dynamic reactive capability and reasonable assumptions of wind plant operation, system transient stability performance is acceptable with fewer capacitors (and possibly smaller/fewer SVCs). This suggests that wind plants with some dynamic reactive capability may reduce or eliminate the need for dynamic reactive devices on the transmission system. Dynamic reactive power supplied close to where it is needed (e.g., at the Type 1 wind turbine generator terminals) will be more effective than the dynamic reactive power at a remote location for the potential problems identified in this transient stability analysis. This will require further analysis to determine the optimal size and location for the dynamic reactive support.

11. The post-transient analysis indicated that the grid performance met applicable WECC planning standards, specifically the post-transient voltage deviation and voltage stability reactive margins. Adequate reactive margins at critical 500 and 230 kV buses were observed for critical contingencies, varying between 950 MVAR and 3,400 MVAR for 500 kV buses and between 600 MVAR and 1,300 MVAR for 230 kV buses.

12. The post-transient analysis also indicated that the proposed transmission system to accommodate the additional new wind generation in the Tehachapi area may be highly compensated with the addition of mechanically switched shunt capacitors. The nose point in the resulting Q-V curves for critical 500 kV buses under critical contingencies was observed to be high in the 0.95 – 1.0 per unit voltage range. Further analysis will be needed to optimize the proposed reactive supports and to evaluate if series compensation would be required to help lower the nose point in the Q-V analysis for critical buses under critical contingencies.

Recommendations Based on the Transmission Planning Study Results

1. All new wind generation plants must meet WECC LVRT requirements.

2. All new wind plants should be Type 3 or Type 4 generators that are capable of providing dynamic reactive support to help the transmission grid meet applicable WECC transient stability performance standards and to prevent potential tripping due to low voltages. In

the event that some of the new wind plants are of Type 1 or 2 with no dynamic reactive capability, the generator owner must provide sufficient reactive resources to meet the Low Voltage Ride Through standards and voltage control standard. Additional studies may be required to verify the generator has provided appropriate additional external dynamic reactive support to meet the interconnection standards.

3. Re-evaluate the optimal location and size for the dynamic reactive support (i.e., SVCs) that were proposed in the Tehachapi Transmission Project plan.

4. Analyze the best solution for improving the nose point of the Q-V analysis for critical 500 kV buses under critical contingency conditions. Potential solutions include the use of series compensation and reduction of proposed shunt compensation.

Analysis of Operating Issues

The operational analysis focused on integrating a total of approximately 6,700 MW of wind generation (~ 2,600 MW existing and ~ 4,100 MW new). The California ISO and Pacific Northwest National Lab jointly performed the analysis on the California ISO-controlled Grid.

The primary objective of the Operating Issues study was to determine the following:

- The magnitude of hourly overall ramping requirements
- Load following capacity and ramping requirements
- Regulation capacity and ramping requirements
- Over-generation issues and potential solutions

The wind generation impact analysis methodology is based on a model of the California ISO's actual scheduling, Real-Time dispatch, and regulation processes and timelines. Minute-to-minute variations and statistical interactions of the system parameters involved in these processes are depicted with sufficient details to provide a robust and accurate assessment of the additional capacity, ramping and ramp duration requirements that the California ISO Automatic Generation Control (AGC) and load following Automated Dispatch System (ADS) systems will be facing when the additional renewable resources have been added to the system to meet the 20% RPS.

Conclusions from the Operating Issues Study

1. Integrating 20% renewables in the California electric power system is operationally feasible, however, changes to operating practices will be required (see Recommendations).

2. The 20% renewables is expected to increase the 3-hour morning ramp by 926 MW to 1,529 MW and the 3-hour evening ramp by 427 MW to 984 MW depending on the season.

3. The California ISO regulation capacity requirements will increase by 170 MW to 250 MW for “Up Regulation” and 100 MW to 500 MW for “Down Regulation”. The amount of increase varies with the season and hour. The fact that this increase in regulation requirements is 10 times larger than in previous studies is due to a detailed model that more accurately represents the time lags in the Automated Dispatch System and in generator response to dispatch commands.

4. The California ISO regulation ramping requirements for the 20% RPS is expected to increase by about ±15 to ±25 MW/min. These increases will affect AGC ramps up to 5-minutes long.

5. The California ISO will also require a significant increase in the supplemental energy stack to meet intra-hour load following needs. The increase is explained by the fact that the Hour-Ahead wind generation forecast error (standard deviation is evaluated as 7% to 9% of the total installed wind generation capacity) becomes comparable with the Hour-Ahead load forecast error (standard deviation is 600 MW to 900 MW). The increase in the use of supplemental energy could potentially increase the 10-minute Real-Time market clearing prices.

6. The California ISO maximum load following ramping requirements for the 20% RPS is expected to increase by about ±30 to ±40 MW/min. These increases will affect ADS ramps up to 20-30 minutes long.

7. The California ISO current generating resources seem adequate to meet the anticipated ramping requirements for load following and regulation. However, during drought conditions or low hydro years, regulating response could be slow due to the reliance of thermal units with slower ramp rates. Depending on system load, additional units may have to be committed on-line to meet regulation needs.

Recommendations from the Operating Issues Study

1. Implement a state-of-the-art wind forecasting service for all wind generator energy production within the California ISO controlled Grid. This includes Day-Ahead, Hour-Ahead and Real-Time wind generation forecasts. These forecasts will be crucial for the unit commitment, scheduling and dispatch processes in the Day-Ahead, Hour-Ahead and Real-Time time frames.

2. Incorporate the Day-Ahead and Hour-Ahead wind generation forecasts (block energy schedules) into the California ISO’s and SCs’ scheduling processes. The Day-Ahead and Hour-Ahead schedules must be based on the forecast wind generation values.

3. Integrate the Real-Time wind generation forecast (average wind generation for 5-minute dispatch intervals) with the Real-Time unit commitment and MRTU dispatching applications.

4. Develop a new ramp forecasting tool to help system operators anticipate large energy ramps, both up and down, on the system. The longer the lead time for forecasting a large ramp, the more options the operators have to mitigate the impact of the ramp.

5. Change the California ISO generator interconnection standards to require compliance of all intermittent resources (grid connected wind generation and solar generation)[5] with the interconnection rules established for the Participating Intermittent Resources Program. These rules include Real-Time meteorological data and telemetry systems to communicate the 4-second meteorological and production data from wind parks to the California ISO. This data needs to be integrated into the California ISO's forecasting software.

6. Implement a procedure where the California ISO dispatcher can send dispatch notices to wind generation operators and require them to implement pro-rata cuts in their energy production. During over-generation periods, when dispatchable generation plants are already operating at their minimum levels, the California ISO needs to have an ability to curtail wind generation on an as needed basis.

7. Analyze the impact of solar power intermittency with load and wind generation intermittency.

8. Evaluate technological changes that can facilitate the integration of large amounts of intermittent resources. For example, evaluate the benefits of participating in a wider-area arrangement like ACE sharing or Wide Area Energy Management system.[6]

9. Study the impact that additional cycling (additional start ups) and associated wear-and-tear issues; dispatches below the maximum unit capacity; and associated additional costs and environmental impacts will have on conventional generation due to the integration of large amounts of intermittent resources. The California ISO will consider whether improvements can be made to its Scheduling, Real-Time Dispatch and Regulation systems that will minimize the impacts on conventional units.

10. Encourage the development of new energy storage technology that facilitates the storage of off peak wind generation energy for delivery during on-peak periods.

11. Include changes in Resource Adequacy standard to require more generation with faster and more durable ramping capabilities that will be required to meet future ramp requirements.[7]

12. Include changes in Resource Adequacy standard to require additional quick start units that will be required to accommodate Hour-Ahead forecast errors and intra-hour wind variations.

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5 Specific reference to wind generation and solar added in response to comment from MWD.

6 Principles of the Wide Area Energy Management system are currently under design at PNNL. The project is sponsored by BPA. The California ISO is a participant in this project.

7 The California ISO is currently participating in a CEC-sponsored project with PNNL and ORNL on the value of fast regulation resources.

Analysis of Forecasting Issues

The California ISO's Market Redesign and Technology Upgrade (MRTU)[8] is expected to help in mitigating ramping problems associated with large amounts of wind generation provided that Day-Ahead and Hour-Ahead wind forecasts are integrated into MRTU. There are occasional problems of too much generation on-line on light load days when wind and hydro generation are at maximum production levels. These high levels of production combined with other generation that must also be on-line results in an over-generation problem. One of the important results from the MRTU Day-Ahead Integrated Forward Market (IFM) will be the creation of feasible generation schedules for the next operating day. The IFM requires accurate Day-Ahead wind generation forecasts as a key input to the RUC process. The goal is to make sure that the right amount of generation is committed to be on-line for the next day operation. Good Day-Ahead market decisions will minimize the start-up of fossil fueled generation that will not be needed when large amounts of wind generation shows up. Better Day-Ahead schedules will decrease the over-generation problems as load and generation will be more closely matched.

Another market issue is the procurement of optimum quantities of Ancillary Services in the Day-Ahead Market. The amount of regulation services needed is expected to increase by 200 to 500 MW, especially for some hours and seasons. Wind variability and unpredictability is much larger in January through April, so the California ISO will need to procure more "Up Regulation" in these months.

The amount of energy and number of bids in the Supplemental Energy Market will need to increase with the additional amounts of wind generation. The additional energy required will be as much as +800 MW (INC bids) and -1,000 MW (DEC bids). This may result in more price volatility in the Real-Time Energy Market due to the large variability of wind generation in certain hours and seasons.

Use of Storage Technology with Wind Generation

Additional storage capability would be of considerable benefit with the integration of large amounts of renewables, especially intermittent resources. Storage systems shift some of the off-peak energy production to deliver at peak periods. Some storage, such as high-speed flywheel systems, can provide regulation services and frequency control. Storage can also help with ramping issues by quickly absorbing excess energy when wind generation ramps up, and it can deliver energy when wind generation ramps down.

"Storage devices such as batteries can be located anywhere on the grid (and can be moved) to support the dual needs of integrating intermittent renewables and mitigating congestion. Mitigating congestion includes deferring or eliminating the need for transmission upgrades near the renewables generation, and for transmission and distribution upgrades near the loads."[9]

8 MRTU is a comprehensive program that enhances grid reliability and fixes flaws in the California ISO markets. It keeps California compatible with market designs that are working throughout North America and replaces aging technology with modern computer systems that keep pace with the dynamic needs of California's energy industry. The program is scheduled for implementation March 31, 2008.

9 Quotation from comments provided by Edward G. Cazalet, Megawatt Storage Farms, Inc.

A proven and deployed storage technology is hydro pump storage. The 1,200 MW Helms pump storage facility[10] that is owned and operated by PG&E is the largest storage facility on the system. The facility can provide regulation services when it is in the generating mode but not in the pumping mode. This plant could be used in combination with Tehachapi wind generation, if the transmission facilities to the Gregg substation are upgraded. This would facilitate the transmission of the Tehachapi energy to the Helms Pump Storage plant, and it would enable the use of the third pump at the plant to store more energy from renewables for more hours per year.

Major R&D projects are underway to develop new storage technology. One example is production of hydrogen with the use of carbon nanotube technology for storage of the hydrogen gas. Other projects include the testing of the Vanadium Redox Battery (VRB) flow battery and the potential use of compressed air storage. A test of a 100 kVA high-speed flywheel was successfully concluded earlier this year, and a 20 MVA flywheel system could be commercially deployed in a year. Lithium-Ion battery storage has been successfully deployed. All of the other storage technologies appear to be a number of years in the future before they are commercially available.

Recommendations for Implementing Storage Technology

1. Initiate a California ISO project for storage technology with the goal of removing technical and economic barriers to the deployment of the technology.

2. Hold stakeholder meetings and workshops to explore market mechanisms for financially compensating storage facilities for the benefits they could provide such as regulation services, other ancillary services, transmission loading relief and voltage support. This is in addition to their ability to shift off-peak energy production to energy delivery on-peak.

Summary

1. The planned $1.8 billion of transmission upgrades for the Tehachapi area are sufficient to support up to 4,200 MW of new renewable resources.

2. New wind generation resources should be Type 3 or Type 4 units as the installation of more Type 1 units in Tehachapi has a negative impact on the reliability of the system.

3. All new generating facilities, including new wind generation facilities, must meet the California ISO Interconnection Standards, provide 4-second operating data and be prepared to act on dispatch notices from the California ISO Operations.

4. Integrating 20% renewables in the current generation mix is achievable; however, several market integration and operational changes are required.

5. Transient stability studies indicated that the new Tehachapi wind generation with Type 3 or Type 4 units, meets WECC LVRT as well as the WECC transient stability standard.

10 The Helms pump storage facility is rated for 1,200 MW in the generating mode and 900 MW in the pump mode.

6. Some of the existing Tehachapi wind generation (Type 1 Units) trips off-line for three phase 500 kV faults in the local area under the full wind scenario.

7. Post-transient governor power flow analysis results indicate that the WECC standards are met.

8. A state-of-the-art wind forecasting service is necessary in the Day-Ahead time frame to minimize errors in the unit commitment process. The accuracy of Day-Ahead load and wind generation forecasts will affect the market clearing prices and unit commitment costs.

9. Approximately 800 mW/hr of generating capacity and ramping capability will be required to meet multi-hour ramps during the morning load increase coupled with declining wind generation. Operations will need to be able to quickly ramp down dispatchable resources during the evening load drop-off and accommodate increases in wind generation.

10. The amount of regulation required will significantly increase with large amount of new wind generation.

11. The size of the supplemental energy stack must significantly increase to meet intra-hour load following needs.

12. The California ISO must have the ability to curtail wind generation during over-generation conditions.

13. Short start units must be available to accommodate Hour-Ahead forecast errors and intra-hour wind variations. The quantity of short start units that will be needed requires additional analysis and modeling.

Chapter 1 - Background

The purpose of this Report is to ensure the successful integration of 20% renewable resources with the planning, and operation of the power grid. The Renewables Workgroup combined the talents and resources within Planning and Infrastructure Development (P&ID), Grid Operations, Market Operations, Information Technology and External Affairs and representatives from General Electric, Pacific Northwest National Laboratory and AWS Truewind. It also involved coordination and collaboration with IOUs, wind generator owner/operators, Scheduling Coordinators, the CEC, industry experts and adjacent balancing authority operators.

The scope of this Report is primarily to provide a detailed focus on Transmission Planning and Operating Issues and secondarily, to focus on forecasting issues and use of storage technology. The goal is to identify any voltage control problems, transient stability performance issues and transmission loading issues. One of the primary drivers behind this Report is to ensure that any transmission control devices (SVCs, reactors, capacitors, etc.) needed to achieve the 20% RPS are ordered as soon as possible.

Chapter 10 of the Report addresses conclusions and implementation tasks going forward. These tasks will focus on the remaining Operational Issues and Forecasting Issues. This includes the need for better Day-Ahead forecasting and use of this information for Day-Ahead Unit Commitment decisions. It also covers technical and forecasting issues on the import of renewables.

California - Home to Diverse Wind Resources

1.1. Wind Generation Fundamentals

To address wind generation and integration issues, it is useful to have a common understanding of some fundamental facts.

1.1.1. Wind generation is an energy resource and not a peaking capacity resource.

The role of wind generation is to displace fossil fuel generation resources, to help the state meet greenhouse gas initiatives and carbon reductions, and to reduce the exposure to volatile natural gas prices. Utilities purchase the power output from wind generators to meet their RPS requirements, and to back down the power required from the more expensive gas fired power plants. Because wind is an intermittent resource, California can not depend on wind generation energy production to meet the peak loads during the summer peak load days. The wind typically does not blow on the hottest day of the year, so the wind generation production is usually less than 10% of its nameplate capacity at the time of the summer peak load.

1.1.2. Wind generation, solar generation and system load are all quite variable.

The variability of any one of these elements may be offset by the other or they can be additive and increase the total variability on the system. To accommodate this increase in variability, the California ISO needs increased flexibility from other resources such as hydro generation, dispatchable pump loads, energy storage systems, and fast ramping and fast starting fossil fuel generation resources. The portfolio of future California resources must reflect this need for very flexible generation resources to assist with the integration of large amounts of intermittent resources. This required increased flexibility will be one of the cost drivers for integration of renewables.

1.1.3. The size of the balancing authority matters.

The larger the balancing authority, the more diversified the resource areas, and the larger the benefits of aggregation. Production from geographically dispersed resources typically have much different meteorological conditions, so they do not all move up and down together. The larger the amount of aggregation, the greater the reduction in variability and the easier it is to forecast the total renewables energy production.

1.1.4. The cost and complexity of wind integration starts low.

The variability of wind generation energy production from a small number of units is usually much less than the variability of system load changes. The system operator is accustomed to dealing with daily load forecast errors, changes in hourly load forecasts and the unpredictability of loads. As the amount of wind generation in an area increases, it will reach a point where its variability is greater than the variability of load. As wind generation further increases, the amount of variability will increase non-linearly. This study focused on the 20% RPS. An increase of the RPS to 33% could more than double the integration problems and costs.

1.1.5. Forecast of wind generation energy production — both Day-Ahead and Hour-Ahead — is an essential integration strategy.

Wind generation energy production is not typically scheduled in the Day-Ahead Market. The forecast for wind generation energy production is a very important component in deciding what other generation should be scheduled for the next day. If 3,000 MW of wind is forecast for the next day, it is inefficient and costly to start up fossil fuel generation that will not be needed. The CEC IAP study and other wind integration studies have pointed out the critical importance of Day-Ahead wind generation forecasts. The Day-Ahead Wind forecast does not have to be 100% accurate to achieve substantial benefits.

1.2. Other Key Factors

1.2.1. Large ramps will be an issue.

There will be periods where wind energy production rapidly declines while simultaneously the load is rapidly increasing. Energy ramps as high as 3,000 MW per hour or larger can occur between 0700 and 1000 hours. Fast ramping generation, such as hydro units, will be essential for the California ISO to keep up with the fast energy changes. There will be other periods, particularly in the winter months, where large pacific storms will impact the wind parks and their energy production will rapidly ramp up to full output. The solution will be the development of new ramp forecasting tools to help the grid operators.

1.2.2. Planning and managing transmission for renewables is a key strategy.

Renewable resources can be built much faster than the required transmission upgrades can be designed, approved and built. New transmission and transmission upgrades are essential to link these locational constrained renewable facilities to the backbone power grid. New strategies are needed to manage the congestion on the transmission network to facilitate the maximum delivery of renewable energy to customer loads.

1.2.3. Coordination with neighboring balancing authorities will be a key to success.

For California to meet the 20% RPS, the California ISO will need to import some of the renewable energy from adjacent balancing authorities. New rules and procedures will be needed to lower the barriers for import and export of intermittent resources between balancing authorities. Coordinated transmission plans as well as coordinated energy scheduling and operating practices will be the keys to success.

1.3. Renewables Portfolio Standard Goals

1.3.1. Twenty Percent (20%) Renewable Resources — 2007 to 2013

Energy from renewable resources is expected to increase by 130% in the next 5 years. This large increase is driven by the state's Renewables Portfolio Standard (RPS), which requires the IOUs to serve 20% of their customers' load from renewable resources. The CEC's forecast of the renewable mix for the 20% RPS is shown in Figure 1-1 below:

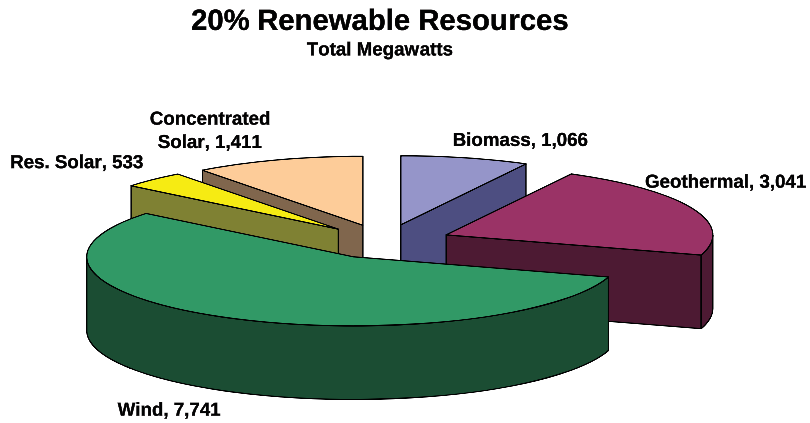


Figure 1-1: CEC Renewable Resources Forecast for 20% RPS

The expected increase in energy renewable resources is as follows:

Table 1-1: CEC Renewables Forecast

Resource	Existing MW	Forecast Additions MW	20% Renewables MW
Biomass	845	221	1,066
Geothermal	1,977	1,064	3,041
Wind	2,706	5,035	7,741
Residential Solar	Unknown	533	533
Concentrated Solar Power	465	946	1,411
Total	**5,993**	**7,799**	**13,792**

The California ISO interconnection queue for renewable resources through the year 2013 contains 14,116 MW of wind generation and 11,264 MW of solar generation. It is not anticipated that all the generation in the interconnection queue will be built by 2013, so the California ISO studies and the CEC studies have scaled back the amount of new renewables generation to the numbers shown in Table 1-1 above. The transmission and operating plans and recommendations contained in this report are based on the scaled back amount of renewables that are forecast to be installed to meet the 20% RPS.

1.3.2. Thirty-Three Percent (33%) Renewable Resources

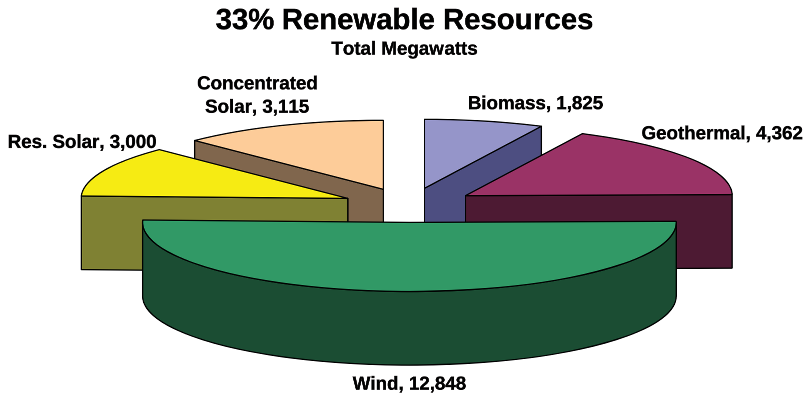


Figure 1-2: CEC Renewable Resources Forecast for 33% RPS

Table 1-2: CEC Forecast for 33% Renewable Resources

Resource	Existing MW	Forecast Additions MW	Total MW
	2006	2020	2020
Biomass	845	980	1,825
Geothermal	1,977	2,385	4,362
High Wind	2,706	9,961	12,667
Low Wind	0	181	181
Res. Solar	Unknown	3,000	3,000
CSP	465	2,650	3,115
Total	**5,993**	**19,157**	**25,150**

The CEC IAP study for 2020 used 12,700 MW of wind and 6,000 MW of solar generation, which is consistent with the numbers in Table 1-2 above from their August 15, 2006 IAP workshop. The 33% RPS goal requires dramatic increases in solar generation as well as wind generation. Many of the most productive wind generation sites will be developed by 2020 or earlier, so solar generation will have to play an increasing role to achieve the 33% RPS goal. The capacity value of the renewable resources typically is 20% to 37% of the nameplate rating of the facility. The capacity factor[11] of 30% means that for every 100 MW of installed nameplate capacity, the facility is only capable of delivering 30% to the total energy potential of the resource on an annual basis. The exceptions are biomass and geothermal resources, which have capacity values of 89% and 90% respectively. Therefore, to increase the amount of energy from renewable resources from 20% to 33% requires approximately a doubling of the installed capacity of the renewable resources.

Note: This California ISO report on the integration of renewables covers only the 20% RPS requirement and does not include an analysis of the 33% goal. The transmission requirements and operational issues to meet the 33% RPS will need to be addressed in a future study.

11 Capacity Factor = actual energy production per year/Nameplate MW * 8760 hours per year.

Chapter 2 – Assessment of the California Energy Commission's Intermittency Analysis Project Final Report

The California Energy Commission sponsored the Intermittency Analysis Project (IAP) in 2006 to study the integration of all renewable resources to meet the state's requirement of 20% of energy from renewables by 2010 and the goal of 33% of energy from renewables by 2020. A public workshop was held on February 13, 2007 where the results of this project were presented. The California ISO met with the consulting team after the workshop to discuss their findings. This included a discussion of the study methodology, the assumptions used in the study, and the results and conclusions in the draft report. The California ISO provided detailed technical comments on the results presented at the workshop and recommended additional study work be done.

The Final CEC IAP Report was released in late July 2007. This report is an excellent document with contributions from many experts and technical consultants. It provides a thorough analysis of many of the integration issues. The report concludes that the 20% renewables requirement can be achieved, but numerous things must be done to ensure success. It would be erroneous to conclude that there are no serious integration problems. In fact, today's operating data with less than 3,000 MW of wind generation have already revealed some operating issues. The addition of 4,500 MW to 6,000 MW of new wind generation will only exacerbate these issues. The California ISO has worked with the CEC consulting team to correct some of the modeling assumptions to ensure the results produced are useful to the California ISO and all the participants in the renewables program.

One issue identified in the draft CEC IAP report that was released in May, 2007 was potential transmission and operating problems under light load conditions. If both hydro generation and wind generation are at maximum energy production and the system load is very low (less than 20,000 MW), there is a good chance the California ISO will have an over-generation condition. There were also unanswered questions about the stability of the system and the potential for serious transmission voltage control problems during these conditions. To address these issues, the California ISO and GE Energy, under the California ISO's direction, jointly performed transient and post-transient system analysis to determine the ability of the system to withstand disturbances and faults during off-peak periods. In addition, contractual and regulatory constraints on the operation of the system were considered in order to address additional mitigation measures. These studies were conducted during summer 2007 and are the basis for a substantial portion of this California ISO report on the integration of renewables.

The Final CEC IAP Report released in July 2007 brings together many different pieces of work that have been done over the past several years. Its emphasis is on ALL forms of renewable resources, not just wind generation. It looks at various scenarios for the increase in the amount of renewable generation resources to uncover potential system problems. It examines transmission issues, operating issues, wind generation forecast strategies, wind turbine technologies and modeling of wind generation, and provides a review of the international experience with the integration of renewable resources. This comprehensive report on the integration of renewable resources will be nationally and internationally recognized as the standard of excellence for renewables integration studies.

The IAP report concludes that the electric system can successfully integrate the amount of renewable resources required to meet the 20% RPS and even the 33% goal if the many recommendations described in the report are adopted. Three issues are key:

1. Major new transmission facilities and upgrades of existing transmission will be required for the 20% RPS and especially to accommodate the 33% RPS goal.

2. Extensive changes will be required in the type of new generation built in the state: new units must have greater operating flexibility to start up and shut down without long delays; they must be able to operate at lower minimum loading levels; and they must have faster ramping capability and regulation capability.

3. Curtailment of some wind generation may occasionally be required, particularly during periods of minimum system load, high wind generation production, low conventional hydro generation flexibility and a lack of ability to export to excess wind generation to other areas.

2.1. Generation Resources Adequacy

The IAP report has a series of important conclusions about future generation procurements and power exchange agreements. It emphasizes the critical importance of much greater flexibility in generator schedules and operational characteristics such as fast ramping, both up and down, and the ability to operate over a wide range of production levels.

The report concludes that the current practice of block hourly import and export schedules between balancing authorities may have to be altered to more frequent updates in schedules to accommodate the variability of renewable resources. This change may take some time to implement on a WECC-wide basis, but it could be tested and implemented between any areas that wanted to make the change.

The CEC IAP report also concludes that the increase in the amount of regulation capability required "is relatively modest (20 MW)." The California ISO disagrees with this conclusion and a major portion of the California ISO's report describes a new methodology for calculating the amount of regulation required. This new methodology more accurately reflects the operational characteristics of the Automatic Generation Control (AGC) and the automatic Supplemental Energy dispatches required to rebalance the system every 5 minutes.

2.2. Transmission Infrastructure

The IAP report correctly concludes that "Significant transmission investments are necessary to meet the 20% and 33% renewable goals." The 33% RPS case requires "128 new or upgraded transmission line segments" to meet load growth requirements as well as upgrades required to accommodate the new generation resources. The estimated transmission and substation costs are $6.4 billion plus land and right of way costs. All of these transmission expansion estimates are based on scenarios of where new renewable resources might be built and how many megawatts of capacity would be located at each site. The California ISO and the transmission utilities will have to develop detailed transmission plans to accommodate the proposed generation resources that have submitted interconnection applications.

2.3. Renewable Generation Technology, Policy and Practice

The California ISO agrees with the conclusion that wind and solar energy forecast will be very important to the success of the renewables program. If the energy production from renewables cannot be forecasted and scheduled, then the value of renewables to displace fossil fueled generation is greatly diminished. The California ISO is looking forward to working with the CEC to develop the best possible forecasting tools to facilitate the integration of the renewable resources into the market schedules and operations.

The new wind turbine technology and solar technology overcome many of the operating limitations of the older technology. New storage technology and transmission congestion monitoring technology may significantly increase the amount of renewable resources that can be accommodated on the system. The increased availability of pump storage facilities (3 pump operation at Helms) can provide needed night time load to accommodate the increased amount of off-peak wind generation. New storage technologies should also be encouraged and tested within the state.

Regulatory policies that present barriers to the successful development of renewable resources must be identified and eliminated wherever possible. An example is the WECC scheduling practice of doing block hour interchange schedules. The transfer of energy from intermittent resources such as wind generation will vary substantially over a one-hour period. If the WECC scheduling process was changed to allow 30 minute interchange schedules between balancing authorities for moving wind generation energy, then it will be easier to schedule the energy, and it would reduce the regulation burden between balancing authorities.[12]

The IAP report also correctly identifies that while operational flexibility of both loads and generation resources is highly desirable from a grid operations perspective, it may not be at all attractive to generation resources and schedulers. Market incentives may be required to secure the flexibility needed to operate the system with large amounts of intermittent resources.

2.4. New Wind Resource Areas

One of the key roles for the CEC is the identification of geographic areas within the state that have high potential value for location of renewable resources. The California ISO's strategy

12 A barrier example was added in response to comment from SDG&E.

for transmission development for location constrained resources is dependent on the CEC's identification of potential areas with significant wind, solar and geothermal energy resources. The February 2007 IAP report "Characterizing New Wind Resources in California" is a good example of the research work that should be done to identify energy resource areas.

2.5. Operations Analysis of Intermittent Generation

The Operations Analysis report by the GE Energy Consulting team provides a very extensive analysis of the operational challenges from large amounts of intermittent resources. They have shown the combined effects of load variability, wind variability and solar variability. It is very encouraging to see how the combination of wind and solar together can reduce the variability of the entire fleet of intermittent resources. The results should be to encourage the continued R&D efforts on solar technology to drive down the cost of this technology and increase the opportunities for its deployment. This California ISO Report uses the GE Energy Consulting team's report as the basis for the more detailed analysis performed. The CEC IAP report on the operational issues has been extensively reviewed at the California ISO as it reveals the operational challenges the California ISO will have to mitigate for the reliable operation of the grid with large amounts of intermittent resources.

2.6. Conclusion

The California ISO applauds the leadership of the CEC in undertaking the IAP study to assess the transmission infrastructure and services needed to accommodate the levels of renewable resources required by the state's policy goals.

Chapter 3 - Transmission Plans for Interconnection of Renewables

This chapter focuses on the addition of 3,540 MW of wind generation in the Tehachapi area. The Tehachapi area is located at the southern end of the San Joaquin Valley in the mountainous region between Bakersfield and Mohave, and it has the largest potential for the development of wind generation in California. As wind generation matured over recent years, so too have requirements for specific performance characteristics of wind plants. The grid performance of individual wind turbine generators and wind plants has changed, and is substantially affected by the wind turbine technology. With large MW and penetration levels, wind generation performance is expected to be similar to that of other generating resources. New wind generators typically meet low voltage ride through standards, voltage control, and other large generator interconnection standards. Consequently, the history of relatively poor grid behavior due to old wind generation technology is not representative of new wind generation.

Interconnection requirements are still evolving, and new WECC and FERC requirements for wind plant performance have been created. These requirements, which must be satisfied by new wind plants in the California ISO-controlled Grid, are expected to relieve some of the problematic behavior of older wind plants. Throughout the work presented in this report, analysis is based on the addition of wind generation that is, at least, compliant with the minimum performance standards currently in effect.

The analyses were conducted jointly between the California ISO and General Electric and entailed traditional power flow, transient stability and post-transient voltage stability analysis to assess the overall impact of renewables integration on the performance of the interconnected transmission grid over a broad range of load and wind turbine technology assumptions. The primary objectives of the studies were to determine compliance with the WECC reliability standards for transient and post-transient conditions. In addition, the studies also evaluated whether the new and existing wind plants meet the Low Voltage Ride Through (LVRT) standards and remain on-line during fault conditions.

The primary objectives of the transmission system analysis were as follows:

1. Evaluate transient stability and post-transient voltage performance of the California ISO controlled Grid with increased levels of wind generation in the Tehachapi area.

2. Evaluate the post-transient voltage stability performance (Q-V analysis) of the California ISO controlled Grid with increased levels of wind generation in the Tehachapi area. The evaluation is based on applicable WECC/NERC planning standards on voltage support and reactive power and the WECC voltage stability assessment methodology.

3. Evaluate wind plant functional characteristics that are necessary to achieve acceptable static and dynamic performance of the California ISO controlled Grid.

4. Determine any needed improvements to the Grid to achieve acceptable performance with increased levels of wind generation and other renewable energy resources.

3.1. Assumptions and Study Methodology

All studies were performed using the WECC 2010 Heavy Summer peak load and the WECC 2012 Light Spring load system conditions with 4,200 MW of total wind generation modeled in the Tehachapi area. These cases were validated in previous studies and they are representative of heavy summer loads and light spring load conditions. Appendix G addresses the transmission planning process and studies performed to determine the transmission infrastructure and reactive requirements required to accommodate up to 4,372 MW of overall generation in Tehachapi.

3.1.1. Assumptions

- All transmission upgrades outlined in Appendix G, Table G-1 were modeled in both base cases.
- Existing Tehachapi wind generation: 722 MW (mostly connected to Tehachapi 66 kV system) were modeled as WECC Type 1 fixed speed conventional induction generator.
- Total new generation for the Tehachapi Transmission Project is 4,372 MW, of which 3,540 MW is new wind generation and 832 MW is composed of combined cycle and gas turbine.
- No dynamic switching of any shunt capacitors was included in the transient stability analysis.
- Reactive support modeled in the studies:
  - The existing reactive resources for the Tehachapi area were modeled with 317 MVAR voltage-controlled shunt capacitors and 500 MVAR fixed shunt capacitors.
  - The proposed new reactive resources were 700 MVAR of voltage-controlled shunt capacitors, 917 MVAR of fixed shunt capacitors and two Static VAR Compensators totaling 800 MVAR (one at Antelope and the other at Vincent 500 kV Substations).
- 1,300 MVAR fixed shunt capacitors were modeled at wind plants.

2010 Heavy Summer Peak Load Conditions – 2010 Heavy Summer Peak Load with 1-in-10 year heat wave demand for Southern California and corresponding peak load in Northern California. Three variations of the Tehachapi wind generation level were studied: 1) wind generation energy production at nameplate capacity, with 474 MVAR of 230 kV shunt capacitors in the Tehachapi area were turned off due to bus voltage greater than 1.05 per unit leaving 869

MVAR in service; 2) wind generation at 25% of rated nameplate capacity, with all 230 kV shunt capacitors in the Tehachapi area turned off; and, 3) wind generation plants off-line, with all 230 kV shunt capacitors in the Tehachapi area turned off. For the studies, all new WTGs were set to regulate terminal voltage to 1.03 per unit. The studies were conducted using the following assumptions:

Table 3-1: Study Assumptions for 2010 Heavy Summer

	Summer 2010 Peak Base Case MW
COI (Path 66) (N to S)	4,284
Path 15 (N to S)	617
Path 26 (N to S)	4,000
PDCI (N to S)	2,000
West of Borah (E to W)	912
Bridger West (E to W)	1,951

2012 Light Spring Load Conditions – Light Spring Load conditions with heavy south to north flows on Path 15. Similar to the Summer studies, three variations of the Tehachapi wind generation level were studied: 1) wind generation energy production at nameplate capacity; 2) wind generation at 25% of rated nameplate capacity with all 230 kV shunt capacitors in the Tehachapi area turned off; and, 3) wind generation plants off-line with all 230 kV shunt capacitors in the Tehachapi area turned off. The studies were conducted using the following assumptions:

Table 3-2: Study Assumptions for 2012 Light Spring

	Spring Off-Peak MW
COI (Path 66) S to N	3,542
Path 15 (S to N)	5,400
Path 26 (S to N)	1,583
PDCI (S to N)	2,200
West of Borah (E to W)	1,256
Bridger West (E to W)	2,000

The baseline analysis for all studies was performed assuming that all new wind plants would be equipped with the WECC Type 3 doubly fed wind turbine generators. The existing wind plants in the Tehachapi area were modeled as WECC Type 1 conventional induction generators. A total of 25 contingencies (11 Category B[13] and 14 Category C[14]) were simulated for each of the seasonal wind generation scenarios. The simulation consists of time-domain simulation following the disturbances to evaluate the system transient stability performance and governor power flow to evaluate the post-transient steady state performance.

Finally, several sensitivity studies were performed by varying the mix of the WTG technologies of the new plants based on the actual installations of new wind plants in 2006 (i.e., 10% Type 1 induction generator, 20% Type 3 doubly fed with power factor control, 50% Type 3 doubly fed with fast voltage regulation and 20% Type 4 full converter induction generators.

13 Category B is the loss of a single element.

14 Category C is event(s) resulting in the loss of two or more (multiple) elements.

3.2. Conclusions

1. With the support of the proposed Tehachapi Transmission Project, 4,200 MW of wind generation in the Tehachapi area can be integrated to the system without causing any transient stability concerns, providing that the wind plants adhere to the WECC LVRT criteria and have some dynamic reactive capability.

2. The dynamics of the bulk power system are not significantly affected by high levels of wind generation (4,200 MW total) in the Tehachapi area. Both transient stability and system damping are satisfactory.

3. The addition of 3,500 MW of Tehachapi wind generation, on the Western Interconnection with more than 100 GW of total generation at light load, has little impact on the frequency response following loss of major generation units (i.e., two Palo Verde nuclear generating units).

4. Dynamic reactive capability at wind plants is required to meet the WECC transient dip performance criteria. Some types of wind turbine technologies include dynamic reactive capability while other types do not (i.e., WECC Types 3 and 4 do provide dynamic reactive capability, while Type 1 does not). Without adequate dynamic reactive capability, wind plants can be expected to trip following major system faults. Voltage dips and spikes, in violation of the WECC criteria, can be expected if a significant number of wind plants connect to the grid without dynamic reactive capabilities.

5. Dynamic reactive capability at wind plants is necessary to ensure system stability. Technology sensitivity analysis shows that system performance is acceptable with either all Type 3 doubly fed WTGs or with a mix of WTG technologies for the new wind plants. The pessimistic test scenario with 100% Type 1 wind plants with no dynamic reactive capability shows an unacceptable response. Therefore, if the dynamic reactive capability is not inherent in the WTG, it must be added to the wind plant.

6. The California ISO may consider requiring that a minimum portion of the required power factor range be dynamic for each new plant. Additional analyses will need to be performed to determine the minimum requirements for the dynamic range.

7. Based on the transient stability and post-transient study results, the bulk system (500 and 230 kV) shunt capacitors and SVCs proposed in the Tehachapi Transmission Project appear to be conservative for the level of wind generation and the system conditions/outages considered in this study. The SVC sensitivity analysis shows that the proposed SVCs were not necessary to achieve acceptable transient stability performance with a likely mix of WTG technologies. With adequate dynamic reactive capability and reasonable assumptions of wind plant operation, system transient stability and post-transient performance is acceptable with fewer capacitors (and possibly smaller/fewer SVCs). This suggests that wind plants with some dynamic reactive capability may reduce or eliminate the need for dynamic reactive devices on the transmission system. Dynamic reactive power supplied close to where it is needed (e.g., at the Type 1 WTG terminals) will be more effective than the dynamic reactive power at a remote location for the potential problems identified in this transient stability analysis. This will require

further analysis to determine the optimal size and location for the dynamic reactive support.

8. The sensitivity analysis shows that the proposed SVCs were not sufficient to achieve acceptable dynamic performance if all of the new wind plants were modeled with 100% Type 1 WTGs and had no dynamic reactive capability. This is a pessimistic assumption, since the majority of the new wind plants that were installed in the U.S. in 2006 were of Types 3 and 4, which provide dynamic reactive support.

9. The post-transient analysis indicated that the grid performance met applicable WECC planning standards, specifically, the post-transient voltage deviation and voltage stability reactive margins. Adequate reactive margins at critical 500 kV and 230 kV buses were observed for critical contingencies, varying between 950 MVAR and 3,400 MVAR for 500 kV buses and between 600 MVAR and 1,300 MVAR for 230 kV buses.

10. The post-transient analysis also indicated that the proposed transmission system to accommodate the additional new wind generation in the Tehachapi area may be highly compensated with the addition of new shunt capacitors. The voltage nose point in the resulting Q-V curves for critical 500 kV buses under critical contingencies is high in the 0.95 – 1.0 p.u. voltage range. Further studies will be required to optimize the coordination between dynamic and static shunt reactive supports and to evaluate if series compensation would be required to help lower the nose point in the Q-V analysis for critical buses under critical contingencies (i.e., tripping of one SONGS unit while the other unit was already out of service in the power flow case).

3.3. Recommendations

1. The new wind plants need to comply with the WECC LVRT requirements.

2. The majority of additional new wind plants need to be of WECC Types 3 or 4 for producing dynamic reactive support to help the transmission grid meet applicable WECC transient stability performance standards and to avoid wind generators tripping due to low voltage conditions. In the event that the new wind plants are of Type 1 or 2 with no dynamic reactive capability, additional studies will be required to determine the appropriate amount of external dynamic reactive support at these wind plants.

3. The reactive support that was proposed as part of the Tehachapi Transmission Project may need to be re-evaluated to determine the optimal location and size for the dynamic reactive support (i.e., SVCs).

4. Additional analysis will be needed to determine potential solutions for improving the nose point for critical 500 kV buses under critical contingency conditions. Potential solutions for improving the voltage nose point include the use of series compensation and reduction of proposed shunt compensation.

3.4. Wind Plant Representation in the Power Flow

Since wind plants normally consist of a large number of individual WTGs, the modeling of the plant for load flow analysis could be simple or could consist of a detailed representation of each WTG and the collector system. The simpler model shown in Figure 3-1 is adequate for most bulk transmission system studies. This model consists of a single WTG and unit transformer with MVA ratings equal to **N** times the individual device ratings, where **N** is the number of WTGs in the wind plant (or those considered to be on-line for study purposes). An equivalent impedance to reflect the aggregate impact of the collector system can be included together with the substation step-up transformer(s). The total charging capacitance of the collector system can also be included. The charging capacitance can be significant since underground cables are often used for the collector system. A third alternative is to model several groups of WTGs, each represented by a single model, with a simplified representation of the collector system. The wind plants included in this study use both of these equivalent modeling approaches.

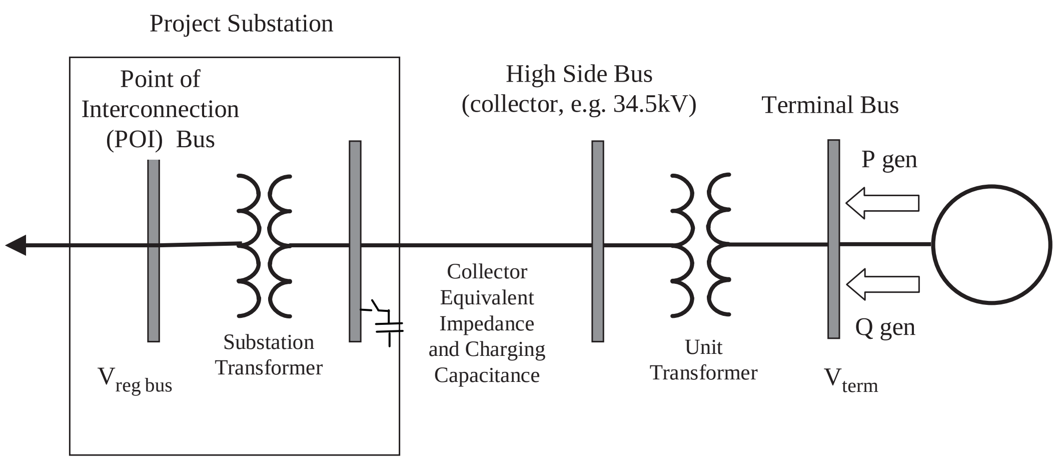


Figure 3-1: Wind Plant Equivalent Model

From an analysis perspective, it is important to understand that the aggregate WTG behaves like a conventional generator connected to a voltage control (PV) bus in the power flow analysis. The generator real power (Pgen) and reactive capability (Qmax and Qmin) are input to reflect the aggregate WTG capability. Typical collector system voltages are at distribution levels (typically 12.5 kV or 34.5 kV) from where a suitable sized substation transformer is used to connect to the grid. Some of the wind plant models in this study include shunt capacitors on the collector side of the substation transformer, as illustrated in Figure 3-1. These capacitors replace or augment reactive capability from the WTGs, so that the power factor requirement of the grid code is met.

3.5. Dynamic Modeling Discussion

As noted above, wind generation technology has evolved rapidly in recent years. Dynamic modeling of wind generation, particularly newer technology WTGs, is a challenge for the industry. The Western Electricity Coordinating Council (WECC) Modeling & Validation Work

Group (MVWG) convened a Wind Generator Modeling Group (WGMG) in 2005 to address the challenge. The charter of that group is to "develop a small set of generic (non-vendor specific), non-proprietary, positive-sequence power flow and dynamic models suitable for representation of all commercial, utility-scale WTG technologies in large scale simulations." The models are suitable for typical transmission planning and system impact studies. All of the current commercially available utility scale wind turbines can be grouped into four basic topologies based on how they interface with the grid. The notation that the workgroup adopted, which is gaining industry acceptance, is as follows:

Type 1 – conventional induction generator

Type 2 – wound rotor induction generator with variable rotor resistance

Type 3 – doubly-fed induction generator

Type 4 – full converter interface

Simple schematics of these four topologies are shown in Appendix F (again, courtesy of the WECC WGMG). Dynamic simulations performed have been based on available industry data and current state-of-the-art models of these different generators.

Type 1 machines operate in a very narrow speed range, and always consume reactive power during operation. The reactive power consumption is a function of active power production and grid conditions, and it cannot be controlled. Consequently, both the reactive power consumption of the generator and the reactive power requirements of the grid must be supplied by additional equipment — usually switched shunt capacitors.

Type 2 machines have wider speed variation and tend to exhibit slower active power fluctuations than Type 1 machines, but have similar reactive power characteristics. Under load, the machines consume reactive power equal to approximately half of the MW output.

Type 3 and Type 4 machines use substantial power electronics to provide wider speed range and finer control of active power production. The power electronics also inherently provide the ability to produce or consume reactive power. It is largely controllable independent from the active power production. In this regard, these machines resemble conventional synchronous generators with excitation systems and automatic voltage regulators (AVR). The details of performance are different between manufacturers. Generally, wind plants with Type 3 or Type 4 generators have the ability to provide relatively fast voltage or power factor control. The ways in which each manufacturer controls and coordinates the reactive power production and balance differs. The great majority of wind generation built in the U.S. in 2006 was of Type 3 or 4.

3.6. Transient Stability Characteristics of Wind Turbine Technologies

The transient stability behavior of the various WTG technologies can be substantially different. Outages that cause deep voltage dips can be problematic for Type 1 plants. A severe voltage dip may cause the induction generators to speed up and eventually pull out of their torque-speed characteristics. This causes them to trip. This response is similar to an induction motor stalling and tripping following a system fault. The risk of tripping is a function of machine characteristics, initial wind power, grid stiffness and dynamic reactive power supply. This type of trip is not a violation of LVRT requirements, as the unit tripping occurs after the fault is cleared. It should be noted that the existing Type 1 plants may or may not have LVRT capability. Therefore, it is possible that the existing plants would trip sooner than these simulations indicate. In cases with new Type 1 plants, they must be LVRT compliant, but they may still trip due to this over speed behavior.

Since Type 3 and Type 4 machines are variable speed, these machines are not limited by conventional transient stability angular constraints. These machines cannot lose local angular stability like a synchronous machine, although it is possible for grid separation to occur. The variable speed controls tend to make this type of wind generator largely unsusceptible to low frequency grid oscillations as well.

3.7. Fault Disturbance List

Twenty-five line faults, generation trips and Pacific DC Intertie (HVDC) outages were studied for the two system conditions (Heavy Summer and Light Spring) and three wind conditions (full, low and no wind). The implementation of two of the faults (Midway-Vincent 500 kV double line outage and the HVDC) varied depending on system conditions. Specifically, the generation special protection scheme associated with the Midway-Vincent 500 kV double line outage was only implemented under Heavy Summer conditions. Under those same conditions, the HVDC fault included the tripping of northwest generation appropriate for the north-to-south direction of flow on the HVDC line. Light Spring conditions, the HVDC fault included the tripping of northwest load appropriate for south-to-north flow.

Table 3-3: Contingency Description

Outage	***Description***
Diablo-g2	Loss of 2 Diablo Canyon Generators.
IPP-bipolar	Loss of IPP bipole with north to south flows.
Lugo-Mira Loma-dlo-12slg	1-phase, 12 cycle fault at Lugo 500 kV. Loss of 2 Lugo-Mira Loma 500 kV lines.
Lugo-Vincent-dlo	3-phase, 4-cycle fault at Lugo 500 kV. Loss of 2 Lugo-Vincent 500 kV lines.
Lugo-Vincent-slo	3-phase, 4-cycle fault at Lugo 500 kV. Loss of 1 Lugo-Vincent 500 kV lines.
Midway-Vincent-dlo-SPS	3-phase, 4-cycle fault at Midway 500 kV. Loss of Midway-Vincent 500 kV lines; SPS generation trip.
Midway-Vincent-dlo-no SPS	3-phase, 4-cycle fault at Midway 500 kV. Loss of Midway-Vincent 500 kV lines.
Palo Verde-g2	Loss of 2 Palo Verde generators.

PDCI-NS-bipolar	Loss of PDCI Bipole with north to south flows.
PDCI-SN-bipolar	Loss of PDCI Bipole with south to north flows.
Palo Verde-Devers-slo	3-phase, 4-cycle fault at Palo Verde 500 kV. Loss of Palo Verde-Devers 500 kV line.
SONGS-g1-svc	Loss of 1 SONGS generator.
Sub.1-Antelope-slo	3-phase, 4-cycle fault at Tehachapi Sub. 1 500 kV. Loss of Tehachapi Sub. 1-Antelope 500 kV line.
Sub.1-Sub.5-slo	3-phase, 4-cycle fault at Tehachapi Sub. 1 500 kV. Loss of Tehachapi Sub. 1-Sub. 5 500 kV line.
Sub. 5-Midway-slo	3-phase, 4-cycle fault at Tehachapi Sub. 5 500 kV. Loss of Tehachapi Sub. 5-Midway 500 kV line.
Sub. 5-South-dlo	3-phase, 4-cycle fault at Tehachapi Sub. 5 500 kV. Loss of Sub. 5-Antelope and Sub. 5-Vincent 500 kV lines.
Vincent-Antelope-dlo	3-phase, 4-cycle fault at Vincent 500 kV. Loss of 2 Vincent-Antelope 500 kV lines.
Vincent-Antelope-slo	3-phase, 4-cycle fault at Vincent 500 kV. Loss of 1 Vincent-Antelope 500 kV line.
Vincent-Mesa230-dlo	3-phase, 4-cycle fault at Vincent 230 kV. Loss of 2 Vincent-Mesa Cal 230 kV lines.
Vincent-Mesa230-slo	3-phase, 4-cycle fault at Vincent 230 kV. Loss of 1 Vincent-Mesa Cal 230 kV line.
Vincent-North-dlo	3-phase, 4-cycle fault at Vincent 500 kV. Loss of Vincent-Antelope-Sub. 5 500 kV lines.
Vincent-Rio Hondo-dlo	3-phase, 4-cycle fault at Vincent 230 kV. Loss of 2 Vincent-Rio Hondo 230 kV lines.
Vincent-Rio Hondo-slo	3-phase, 4-cycle fault at Vincent 230 kV. Loss of 1 Vincent-Rio Hondo 230 kV line.
Imperial Valley-Windfarms-slo	3-phase, 4-cycle fault at Imperial Valley 500 kV. Loss of Imperial Valley-Windfarms 500 kV line.
Windfarms-Miguel-slo	3-phase, 4-cycle fault at Windfarms 500 kV. Loss of Windfarms-Miguel 500 kV line.

3.8. Performance Criteria

System performance was evaluated based on "WECC Planning standards, WECC Disturbance-Performance Allowable Effects on Other Systems." In particular, voltage and frequency dips violating the WECC criteria at load buses were identified. Tripped wind turbine generators and new wind turbines within 90% of LVRT were also identified. The following specific performance tests conform to the WECC LVRT standard and were run on all simulations:

- Identify load-bus voltage dips exceeding 20% for more than 20 cycles for n-1 contingencies.

- Identify load-bus voltage dips exceeding 20% for more than 40 cycles for n-2 contingencies.
- Identify load-bus frequency dips below 59.6 Hz for more than 6 cycles.
- Identify new WTGs with 15% or greater voltage dip for 2.41 seconds.
- Identify new WTGs with 45% or greater voltage dip for 1.56 seconds.
- Identify new WTGs with 65% or greater voltage dip for 0.99 seconds.
- Identify new WTGs with 80% or greater voltage dip for 0.14 seconds.
- Identify new WTGs with 85% or greater voltage dip. This corresponds to the original FERC Order 661A minimum voltage recommendation.
- Identify new WTGs with 25% or greater voltage rise for 0.09 seconds.
- Identify all tripped generators.

3.8.1. Transient Stability Performance

Baseline simulations modeled all new wind projects with WECC Type 3 WTGs (doubly-fed induction generator). Existing wind farms in the Tehachapi area were all modeled with WECC Type 1 WTGs (induction generators).

Twenty-five single line, double line, generation trip and HVDC outages were studied for the two system conditions (Heavy Summer and Light Spring) and three wind conditions (full, low and no wind). In particular, voltage and frequency dips violating the WECC criteria at load buses in California were identified. Tripped wind turbine generators were also identified.

A discussion of system performance with high concentrations of new wind generation follows.

3.8.2. WECC 20% Voltage Dip Criteria

The Vincent-Antelope 500 kV single line outage was the only Category B outage that caused a voltage dip below 20% for more than 20 cycles at a load bus. The violation only occurred at the Cal Cement 66 kV bus under Light Spring conditions with full wind output. The bus voltage dipped to 38% and was below 20% for 21 cycles. This bus is located close to the existing Tehachapi wind parks. The low voltage dip and slow recovery is primarily caused by the response of the existing Type 1 induction generator wind turbines.

None of the WECC Category C outages caused voltage dips greater than 20% for more than 40 cycles.

3.9. Wind Turbine Trips

While there was only one outage that caused a WECC 20% voltage dip criteria violation at a load bus, several outages caused deep prolonged voltage dips at and around existing wind plants. Trips only occurred for full wind conditions, with all wind plants at 100% MW output. Only existing wind plants (WECC Type 1, induction generators) tripped. Under the base modeling assumption that all new units are WECC Type 3, the new units were able to ride through all faults and generation outages without tripping. Figure 3-2 shows bus voltages for the Vincent-Antelope 500 kV single line outage fault for the Light Spring condition. This case had 270 MW of wind generation tripped for the full wind condition, and was the only case to cause WECC voltage dip violations. The top two plots show the Breeze and Cal Cement 66 kV load bus voltages. Under full wind, the voltage at Breeze recovers just within the WECC 20% voltage dip criteria, remaining below 20% for 20 cycles. The Cal Cement bus fails the criteria with a dip below 20% for 21 cycles. For low wind and no wind conditions, the voltage recovery meets the WECC criteria.

The middle two plots show the Tehachapi Sub. 1 500 kV and 230 kV bus voltages. The 500 kV voltage dips during the fault, but recovers to its initial value in about 0.5 seconds. Upon fault clearing, the 230 kV bus voltages settle below 0.8 per unit. At 0.5 seconds after the fault, several existing Type 1 wind plants begin to trip. Within a few tenths of a second, all 270 MW of wind turbines tripped. This caused an over-voltage condition on the 230 kV bus. With low wind and no wind, the 230 kV voltages recover within 0.5 seconds, and there are no wind turbine trips.

The last two plots show the TehachMM and Eastwind 570 volt bus voltages. These show the lack of voltage recovery of Type 1 wind plants following the fault under full wind condition. The voltage dip causes the induction generators to speed up and eventually pull out of their torque-speed characteristics. This increases the reactive power consumption of the induction generators and keeps voltage throughout the area depressed. The poor voltage recovery is made worse by the relatively weak 66 kV transmission system connecting the existing wind plants.

This is not an LVRT issue, since the units are able to ride through the fault. Rather, it is a fast voltage collapse caused by the induction generators on a weakened transmission system with a lack of dynamic reactive support. This is the same phenomenon as the fast voltage collapse caused by induction motors stalling.

For the simulations in this study, the Type 1 units are tripped based on an under-voltage function (voltage less than 0.85 per unit for more than 0.5 seconds). The actual protective function tripping an induction generator under these conditions could be under-voltage, over-speed or over-current. The timing of a trip could range from fractions of a second to several seconds. The longer the trip time, the greater the potential of a cascading event whereby additional wind turbines and customer loads are tripped. The extent of generation and load loss cannot be accurately predicted through simulations.

Figure 3-2 shows that the behavior of the older, existing wind plants is poor. As noted previously, the behavior of these machines is they trip from under-voltage but their performance is not exactly captured by the model. Details of the behavior are likely to be different. However, the most important observation from this case comes from comparison to the new wind plants, as shown in Figure 3-3.

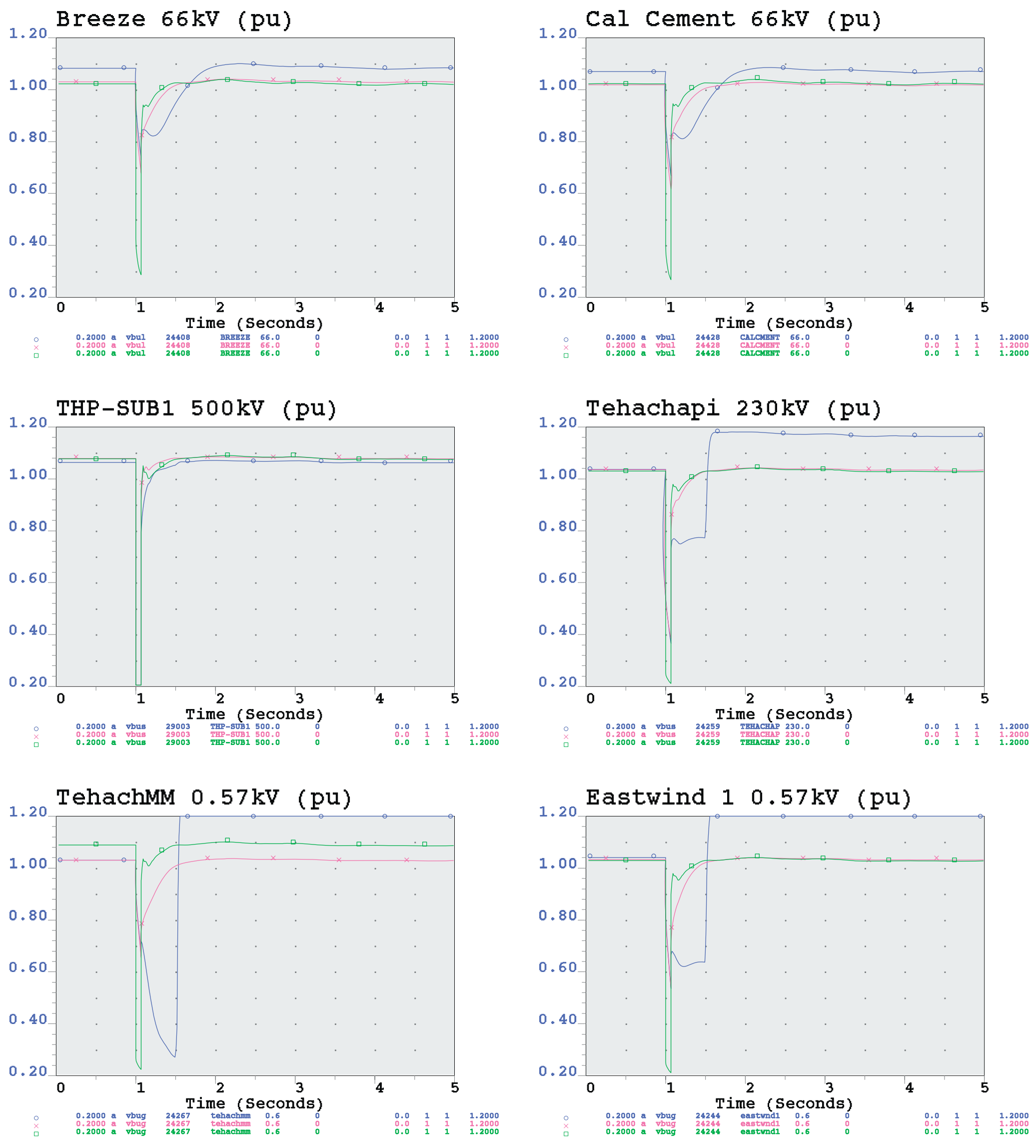


Figure 3-2: Bus Voltages Near Existing Wind Plants Following the Vincent-Antelope (SLO) for 2012 Light Spring – Full Wind, 25% Wind and No Wind Conditions

Figure 3-3 shows a plot of representative 230 kV bus voltages near new WECC Type 3 wind plants. The terminal voltages of the new wind plants recover within 0.25 seconds of fault clearing. The voltage recovery is actually faster with the wind turbines on-line (full wind and low wind) than off-line (no wind). This is due to the dynamic voltage support of the Type 3 doubly-fed induction generators. The good behavior of the new plants is largely decoupled from the poor behavior of the existing wind plants.

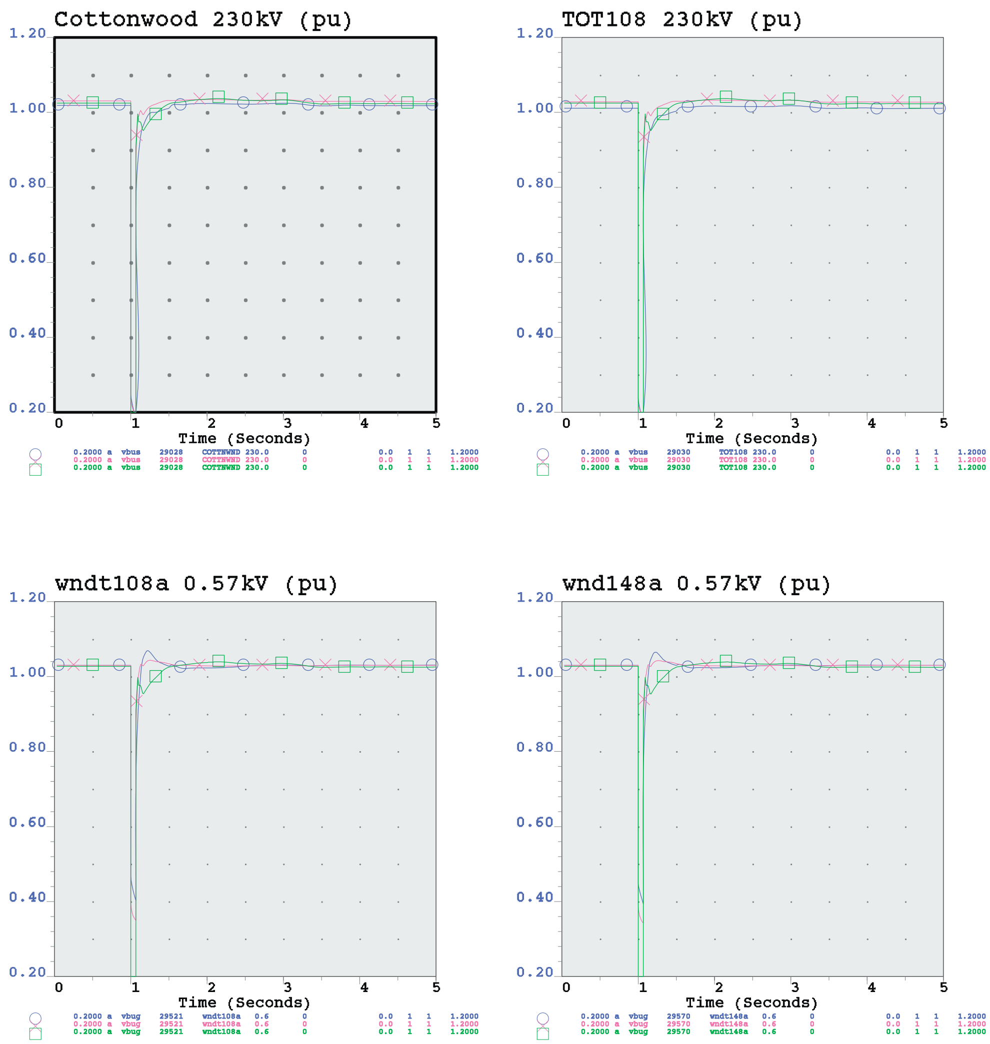


Figure 3-3: Bus Voltages Near New Wind Plants Following the Vincent-Antelope (SLO) for 2012 Light Spring, Full Wind, Low Wind and No Wind Conditions

As noted above, none of the outages tested caused new Type 3 doubly fed wind plants to trip. Furthermore, none of the new Type 3 wind plants came within 90% of the LVRT trip points.

3.10. Frequency Response

None of the contingencies resulted in WECC frequency dip violations. Furthermore, there was no measurable difference in the system frequency between the full wind, low wind and no wind cases for the generation trip contingencies. A comparison of the three wind conditions is shown in Figure 3-4 for the loss of two Palo Verde generators for the Light Spring conditions. The plot shows Antelope 500 kV bus voltage and frequency, Antelope SVC output, a 230 kV bus voltage near a new wind plant, Path 26 power flow and San Onofre real power output. The full wind (blue), low wind (red) and no wind (green) cases are all shown.

The frequency at Antelope dips to about 59.7 Hz and begins to recover within about 8 seconds of the generation trip. The Antelope frequency is improved slightly with the higher level of wind generation. The Path 26 power flow and San Onofre power output are all nearly identical for the three wind conditions.

3.11. Power Swings

The plots in Figure 3-4 show very little difference in power swings on Path 26 or San Onofre power output for the different wind scenarios. This is consistent with results from all the generation and HVDC trip scenarios. The addition of about 3,500 MW of new wind generation in Tehachapi and the associated redispatch of existing generation with more than 100 GW of total generation in the Western Interconnection does not affect power swings on the California ISO system.

3.12. Summary of Baseline Performance

The baseline analysis modeled all new wind projects with the WECC Type 3 WTGs (double-fed induction generators) and the existing wind plants with the WECC Type 1 WTGs (induction generators). Under this assumption, the new wind plants do not cause performance problems on the California ISO controlled Grid. The LVRT requires the wind plants to remain on-line following major grid disturbances. The dynamic voltage support provided by the Type 3 machines improves the system voltage recovery after fault clearing.

An additional factor that contributes to the performance of the new wind generation is the transmission interconnection points. The new wind projects are connected to strong 230 kV Substations with sufficient transmission capacity to withstand nearby faults.

The new wind turbines have very little impact on power swings or the California ISO interface flows. The frequency response following the loss of large thermal generation is not affected by the additional wind generation.

The existing Type 1 wind plants do not have dynamic voltage control ability. On the contrary, they degrade voltage recovery following nearby faults. While the units may be able to ride through transmission system faults, they may not be able to remain on-line. Their poor voltage recovery could lead to a localized voltage collapse and the loss of several hundred MWs of existing wind generation. The weak 66 kV system that many of the existing wind plants are connected to compounds this problem.

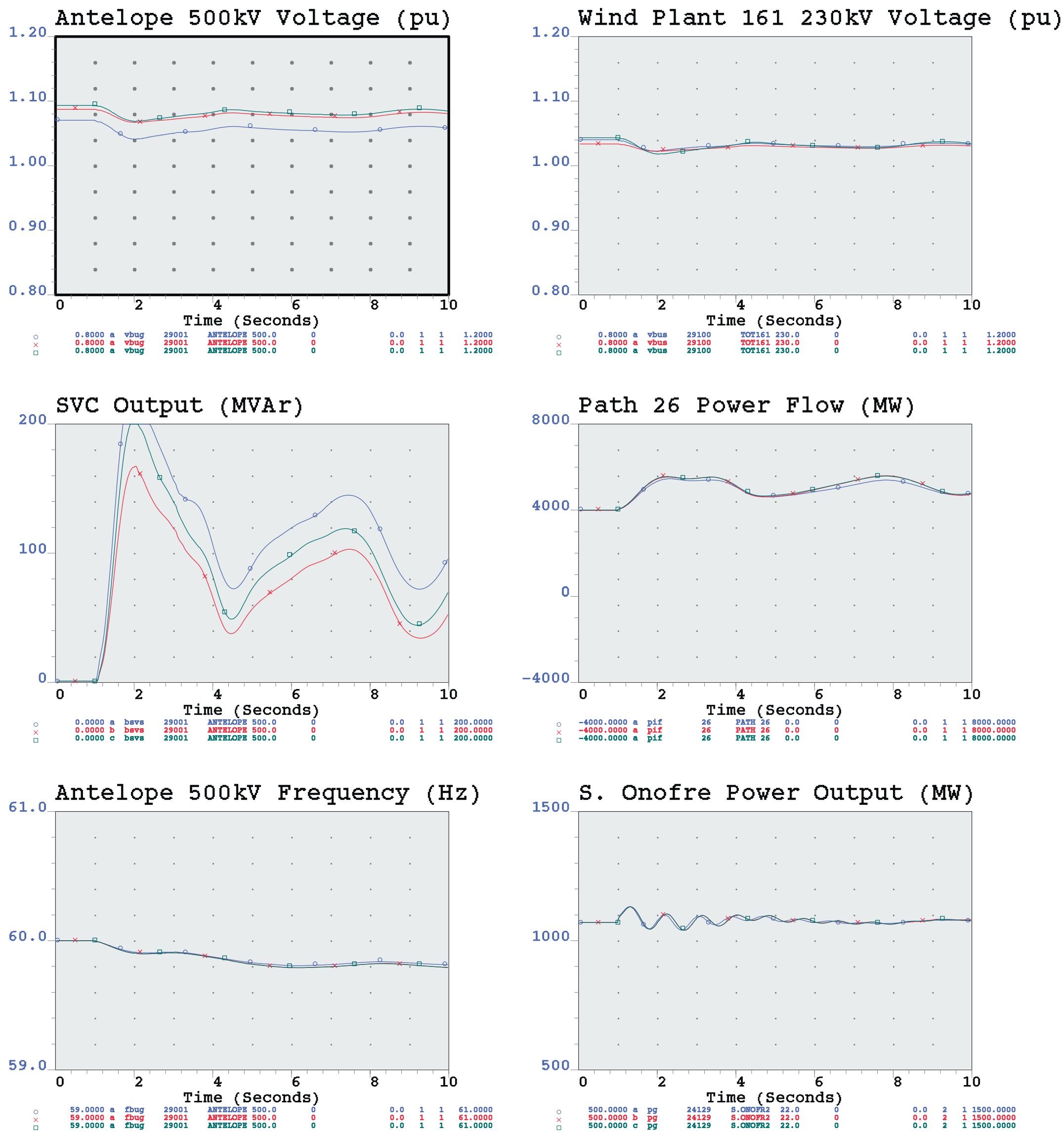


Figure 3-4: System Performance Overview, Loss of Two Palo Verde Generators, 2012 Light Spring Load (Blue-Full Wind; Red-Low Wind; Green-No Wind)

3.13. WTG Technology Sensitivity Cases

The sensitivity of power system performance to WTG technology was tested for the most severe faults identified in the baseline analysis.

- Vincent-Antelope 500 kV double line outage
- Midway-Vincent 500 kV double line outage
- Sub. 5-South double line outage
- Loss of 2 Palo Verde generators

Both the Heavy Summer and Light Spring conditions were evaluated with all new and existing wind plants at full output.

As noted above, the baseline analysis was performed assuming all new wind plants would use Type 3 doubly fed WTGs. Two additional scenarios were evaluated. The first assumed a mix of WTG technologies in the new plants, as follows:

- 10% Type 1 induction generator
- 20% Type 3 doubly fed with power factor control
- 50% Type 3 doubly fed with fast voltage regulation
- 20% Type 4 full converter

This mix was based on the technology distribution of the wind plants or individual WTGs installed within the U.S. in 2006.

The second scenario assumed all new wind plants would use Type 1 induction generator WTGs. Given the 2006 technology distribution, this is a pessimistic scenario.

A comparison of system performance for the three WTG technology scenarios is shown in Figure 3-5. The Vincent-Antelope 500 kV double line outage was applied to the Light Spring conditions with full wind plant output. The black line represents the baseline performance with 100% Type 3 doubly fed wind plants, the red line represents the mixed WTG technology scenario, and the green line represents the 100% Type 1 induction generator scenario.

System response with all new wind plants using Type 3 doubly fed WTGs meets WECC voltage and frequency criteria, and results in the loss of 270 MW of existing Type 1 induction generator wind plants. System response with the mix of WTG technologies in the new wind plants also results in the loss of 270 MW of existing Type 1 wind plants. System response with all new wind plants using Type 1 WTGs was unacceptable. Approximately 4,000 MW of Type 1 wind plants, both old and new, tripped during the simulation.

System performance is acceptable with all Type 3 doubly fed WTGs in the new wind plants. System performance is also acceptable with the mix of WTG technologies in the new wind plants, but the fault recovery is slightly slower. Thus, the wind plants with dynamic VAR capability (i.e., Type 3 doubly fed and Type 4 full converter) support those without such capability. As noted above, the new Type 1 induction generator wind plants in this analysis are WECC LVRT criteria compliant but do not have any dynamic VAR range. Thus, the pessimistic test scenario with 100% Type 1 wind plants with no dynamic VAR capability showed an unacceptable response. This sensitivity analysis suggests that some dynamic VAR capability may be necessary to ensure system stability. Therefore, if the dynamic VAR capability is not inherent in the WTG, it may need to be added to the wind plan or to the local transmission system.

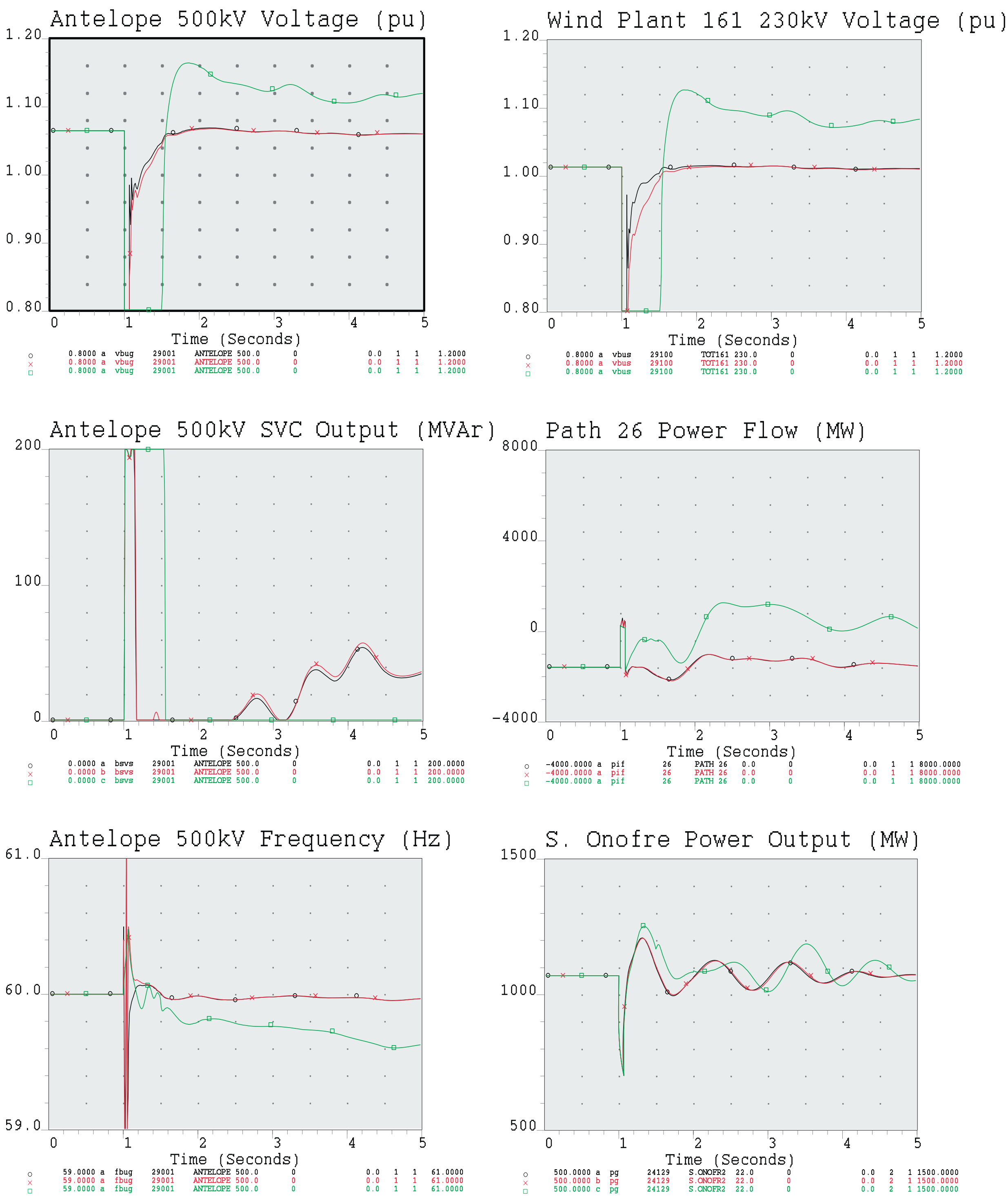


Figure 3-5: System Performance Overview, Vincent-Antelope 500 kV Double Line Outage, 2012 Light Spring Load, Full Wind Plant Output (Black-100% Type 3 Doubly Fed; Red-Mixed Technology; Green-100% Type 1 Induction Generator)

3.14. Dynamic Reactive Compensation Sensitivity Cases

While analyzing the baseline simulation results, it was observed that the Antelope and Vincent SVCs were not providing much reactive power to the system after fault clearing. Rather, the SVCs were providing reactive power during the fault and then again several seconds after the fault. Therefore, an evaluation of SVC response was also performed. The sensitivity analysis evaluated the Heavy Summer conditions for the following most severe faults identified in the baseline analysis:

- Vincent-Antelope 500 kV double line outage
- Midway-Vincent 500 kV double line outage
- Sub. 5-South 500 kV double line outage

All wind plants were at full power output, with mixed WTG technologies in the new wind plants and Type 1 induction generator WTGs in the existing wind plants.

A comparison of system performance for three SVC scenarios is shown in Figure 3-6. The Vincent-Antelope 500 kV double line outage was applied to the system with full wind plant output. The black line represents the baseline performance with the 200 MVAR Antelope and 600 MVAR Vincent 500 kV SVC model as provided, the red line represents performance with modified dynamic SVC models at both locations, and the green line represents performance with neither SVC in service.

The modified dynamic model of the Antelope SVC provides more reactive power post-fault than the original model. As a result, the immediate post-fault voltage on the Antelope 500 kV bus is increased by about 2%. System response with both SVCs out of service is nearly identical to that with the original SVC model. The WECC voltage and frequency criteria were met, and the total loss of existing Type 1 induction generator wind plants was unchanged.

This analysis shows that the SVCs were not necessary to achieve acceptable performance with a likely mix of WTG technologies. If the SVCs are needed for other reasons, the dynamic models should be tuned to achieve better SVC response.

This analysis also shows that the SVCs were not sufficient to achieve acceptable performance with 100% Type 1 WTGs and no dynamic reactive capability in the new wind plants. This suggests that wind plants with some dynamic VAR capability will reduce or eliminate the need for dynamic reactive devices on the transmission system. Reactive power supplied close (e.g., at a wind plant Substation) to where it is needed (e.g., at the Type 1 WTG terminals) will be more effective than reactive power at a remote location for the potential problems identified in this transient stability analysis.

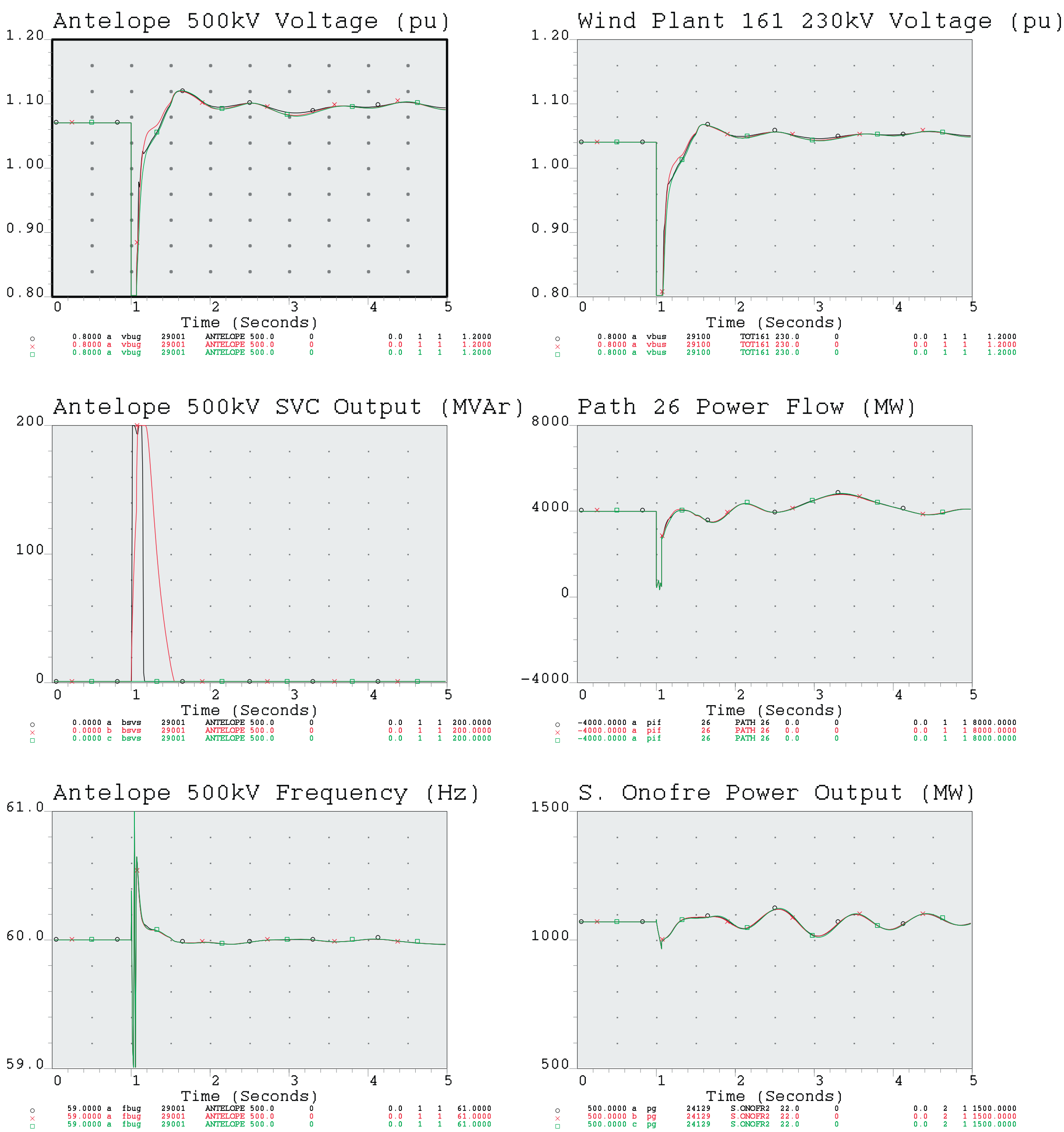


Figure 3-6: System Performance Overview, Vincent-Antelope 500 kV Double Line Outage, 2010 Heavy Summer Load, Full Wind Plant Output, Mixed Technology (Black-Nominal SVCs; Red-Modified SVCs; Green-No SVCs)

3.15. Post-Transient Studies

Post-transient governor power flow studies were performed to evaluate the following:

- Post-transient voltage deviation analysis under three Tehachapi wind generation levels (i.e., full wind, low wind with 25% of nameplate capacity, and no wind) for both the 2010 Heavy Summer load and the 2012 Light Spring load conditions;

- Voltage stability assessment through Q-V analysis to determine reactive margin at key bus voltages under various critical contingencies.

3.15.1. Post-transient voltage deviation analysis

Post-transient governor power flow analyses were performed for the following 23 contingencies:

1. Palo Verde – Devers 500 kV single line outage
2. Vincent – Rio Hondo 230 kV single line outage
3. Sub. 5 (aka Whirl Wind) – Midway 500 kV single line outage
4. Vincent – Antelope 500 kV double line outage
5. Lugo – Mira Loma 500 kV double line outage
6. Vincent – Rio Hondo 230 kV double line outage
7. Vincent – Mira Loma 500 kV single line outage
8. Sub. 1 (aka Wind Hub) – Antelope 500 kV single line outage
9. Vincent – Antelope 500 kV single line outage
10. Vincent – Mesa 230 kV single line outage
11. Diablo G-2 (two nuclear units) outage
12. Vincent – North 500 kV double line outage (i.e., Vincent – Antelope & Vincent – Sub. 5 500 kV lines)
13. Vincent – Mesa 230 kV double line outage
14. Lugo – Vincent 500 kV double line outage

15. Sub. 1 – Sub. 5 500 kV single line outage

16. Lugo – Vincent 500 kV single line outage

17. Sub. 5 – South 500 kV double line outage (i.e., Sub. 5 – Antelope & Sub. 5 – Vincent 500 kV lines)

18. Midway – Vincent 500 kV double line outage (#1 & 2-500 kV lines)

19. Imperial Valley – Miguel 500 kV single line outage

20. Intermountain Power Project DC (IPPDC) bipolar outage

21. Palo Verde G-2 (two nuclear units) outage

22. Pacific DC Intertie (PDCI) bipolar outage

23. SONGS G -1-1 (one SONGS out of service initially, followed by the second unit outage)

3.15.2. Voltage stability (Q-V) analysis

Q-V analysis was performed for all critical 23 contingencies to determine the following:

1. Whether the integration of 4,200 MW wind generation meet applicable WECC planning standards by having positive reactive margin at key monitored buses under critical contingencies;

2. Whether the proposed reactive support provides satisfactory voltage performance (i.e., nose point voltage) under critical contingencies;

3. Whether additional analyses will be required to determine the optimal reactive support to meet the WECC voltage stability planning standards and to achieve better voltage performance (i.e., nose point) under Q-V analysis.

The buses monitored are located within PG&E and SCE systems near the Tehachapi wind pants: Midway 500 kV, Vincent 500 kV, Sub. 1 500 kV, Antelope 230 kV and High Wind 230 kV. In addition, major load bus such as Mira Loma 500 kV and major switching station such as Lugo 500 kV were also evaluated. To determine the available reactive margin at a specific bus, a fictitious synchronous condenser with a reactive range of ±3,000 MVAR[15] was modeled, with scheduled voltage reduced automatically, by using a program, in small increment until voltage collapse is expected. A system voltage is unstable if the bus voltage magnitude decreases as the reactive power injection is increased.

15 This range can be changed for higher value for the Q-V analysis. The higher range requires more computation time.

Following is the summary of the Q-V study results:[16]

1. The post-transient analysis study results indicate that the grid performance meets applicable WECC planning standards on voltage stability. Adequate reactive margins at critical 500 and 230 kV buses were observed for critical contingencies, varying between 950 MVAR and more than 3,000 MVAR for 500 kV buses and between 600 MVAR and 1,300 MVAR for 230 kV buses.

2. The Q-V plots from the Heavy Summer load scenario (shown in Figure 3-7) indicate that the full-wind generation level corresponds to the least amount of available reactive margin. This condition is likely caused by a high level of power transfer (approximately 6,300 MW) between the Tehachapi wind plants and imports from PG&E (via Path 26, which is the Midway-Vincent 500 kV intertie between PG&E and SCE systems), and the load centers in the L.A. basin. On the other hand, with partial wind generation output (i.e., 25% of nameplate capacity), the resultant reactive margin is better than the scenario where there is no wind generation. This indicates that better reactive margin performance, under the partial wind generation scenario, is contributed by the new wind turbines providing reactive support to the system under critical contingencies.

3. The Q-V analysis for the Heavy Summer load conditions indicate that the proposed transmission system to accommodate the additional new wind generation in the Tehachapi area may be highly compensated with the addition of new shunt capacitors. This is shown on the Q-V plots with high voltage nose points for various 500 kV buses under critical contingencies in the range of 0.95 – 1.0 p.u. voltage. Further analysis will be needed to optimize the additional reactive supports and to evaluate if series compensation would be required to help lower the voltage nose point in the Q-V analysis. See Figure 3-8.

4. For the analysis of the Heavy Summer load conditions, the new wind farms in the Tehachapi area were studied with the assumption that there would be no reactive consumptions at the wind plants. To accomplish this, the terminal voltage at the wind farms were scheduled higher (i.e., typical set point was 1.03 p.u. for many of these wind plants) to provide reactive support and to maintain power factor close to unity at its terminal voltage. If the plant's terminal voltage was inadvertently scheduled lower, then it may trigger the plant to absorb reactive power. Consequently, this will affect the Q-V analysis results as this may show higher voltage nose point due to the utilization of additional shunt capacitors at the point of interconnection to maintain a minimum 0.95 power factor.

5. The study results for the Light Spring load scenario for three generation levels from the Tehachapi wind farms indicate that WECC voltage stability standards are met. The voltage performance is also satisfactory, with nose point below operating voltage. On some of the Q-V plots where the lines are flat out at -3,000 MVAR, the cause is due to the maximum set point at -3,000 MVAR for the fictitious synchronous condensers. See Figure 3-8.

16 The results shown for the SONGS G-1-1 as the critical contingency for the Heavy Summer load and Midway – Vincent 500kV double line outage for the Light Spring load conditions

2010 Heavy Summer (G-2 - Loss of Two Songs Units)

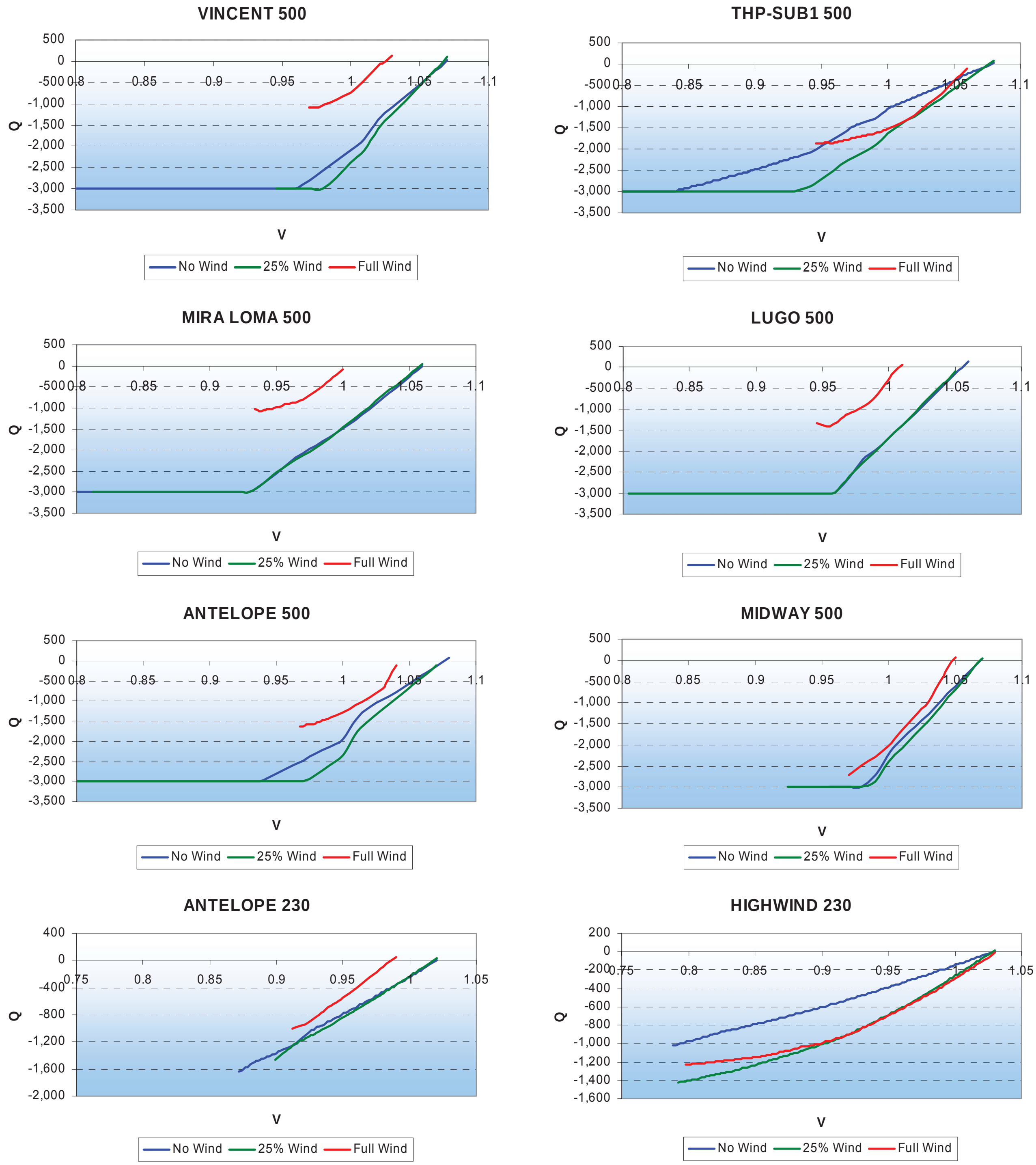


Figure 3-7: 2010 Heavy Summer (G-2 - Loss of Two Songs Units)

Note: The maximum set-point for the Q-V plots where set at -3000 MVAR.

Post-Transient Voltage Stability Analysis
2012 Light Spring (Midway-Vincent DLO)

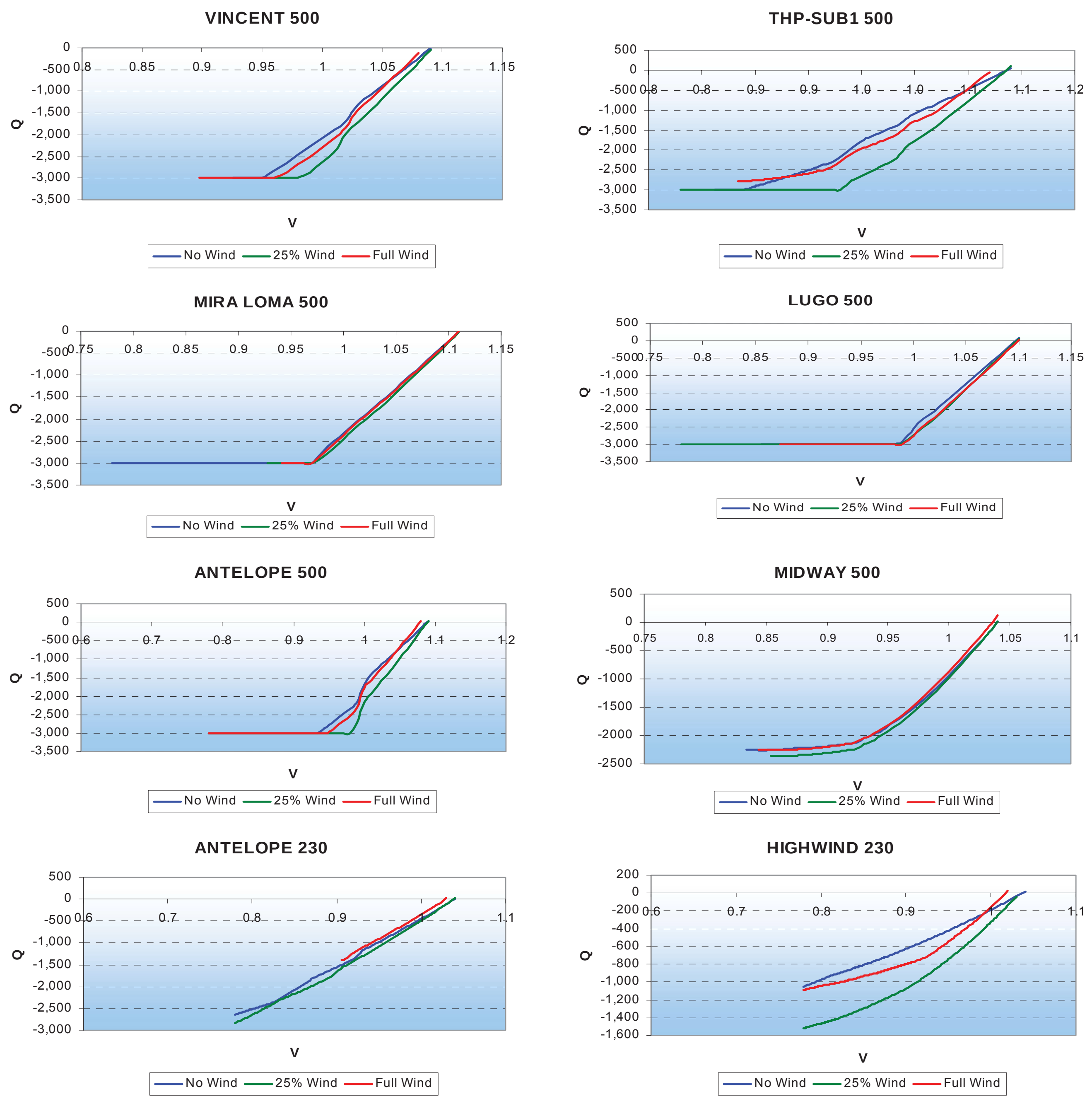


Figure 3-8: 2012 Light Spring (Midway-Vincent DLO)

Note: The maximum set-point for the Q-V plots where set at -3000 MVAR.

3.16. Generator Interconnection Standards

In the last two years, there has been a substantial increase of proposed renewable projects in the California ISO generator interconnection queue, mostly due to California's RPS goals. The total renewable capacity in the queue almost doubled from 5,717 MW in January 2006 to 10,994 MW in January 2007, and tripled in the first half of 2007 to 32,719 MW. History indicates that less than half of this capacity will actually come on-line. Projects included in the queue represent both real projects with financing, site control and purchase power agreements as well as speculative projects that many never come to fruition. Under FERC rules, these extremely different projects must be treated the same. Moreover, if a project leaves the queue at any point in time, every project behind it requires complete restudy, which adds further complication and delays of interconnection.

To improve the legitimacy of the queue and increase the success rate, some changes to the FERC-mandated Large Generator Interconnection Process should be considered, including the following:

- Require all applicants to prove absolute site control prior to being assigned a queue position.
- Only allow projects with commercial on-line dates within 5 years (or other time frame) be allowed in the queue.
- Require higher deposits with LGIP applications and at each study phase.
- Force grouping/clustering of projects in same localized areas.
- Require strict valid technical data requirements with interconnection request.
- Require a third party to perform economic reality checks.
- Allow the ability to move forward projects in the LGIP study process that are proposed in known transmission rich areas and have no system impacts.
- Allow the California ISO tighter control of study timelines with possible penalties for PTOs/California ISO/Generators for missing deadlines.
- Remove the 3-year commercial on-line date (COD) extension option from the LGIP process or require system upgrade payments in accordance with original COD.
- Require wind developers to submit technical data per the LGIP in the same way as other developers. Currently, FERC Order 661 allows wind developers to have 6 months to submit technical data. This impedes study progress on projects behind the wind project(s) in the queue.

It is understood that these proposed changes to LGIP would have to be developed through a formal stakeholder process and ultimately filed with FERC for approval, and this could prove to be a lengthy process. The length of this process will likely be less if the CPUC and other state agencies participate in this process and support these reforms.

3.17. WECC Low Voltage Ride Through Standard (LVRT)

On May 22, 2007, the WECC Wind Generation Task Force (WTF) published a white paper on the proposed WECC LVRT Standard. Titled "The Technical Basis for the New WECC Voltage Ride-Through (VRT) Standard", the paper proposes bringing the WECC LVRT standard in line with FERC Order No. 661-A, which specifies the unit must be able to handle zero volts for 9 cycles. The goal is to modify the existing WECC LVRT Standard that was approved by the WECC Board in April 2006. The paper presents arguments for numerous requirements that should be improved in the new proposed standard. Please refer to Appendix F.

Chapter 4 – Forecasting Issues

4.1. Market Operations – Day-Ahead Time Frame

The California ISO Day-Ahead (DA) load forecast is calculated by utilizing neural-network forecasting software. Multiple weather forecasting data sources are used to determine the weather forecast. To ensure the average load forecast error is minimized, the California ISO continuously monitors and revises its weather forecast and subsequently its load forecast. Load Serving Entities (LSEs) also forecast their hourly load demand, which they use to schedule energy demand in the California ISO's DA market. Like all forecasts, there are scheduling errors associated with the LSEs' DA scheduled load and the actual load. In addition to the California ISO load forecasting errors and the LSEs' scheduling errors, uncertainties are also introduced in the DA scheduling process because intermittent resources are not required to submit DA schedules.

Currently, uncertainty associated with forecasting the output levels of intermittent resources in the DA time frame do not pose any reliability concerns because the actual wind generation output is typically less than 1,100 MW. As shown in Figure 4-1, with the 20% RPS build out, wind generation may peak as high as 6,000 MW, and production levels could exceed 2,000 MW for approximately 50% of the year. A lack of DA forecasts for this amount of wind generation could result in significant reliability issues.

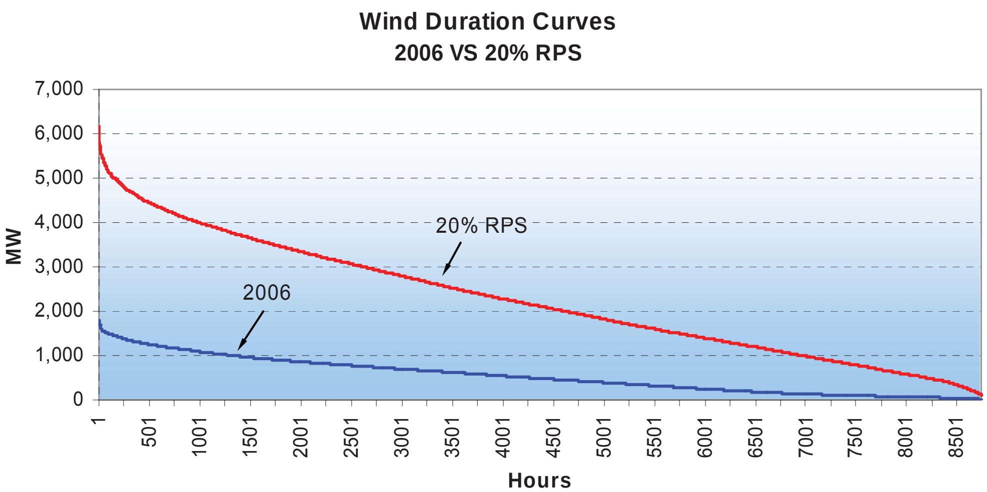


Figure 4-1: Actual Wind Generation for 2006 vs. Expected Wind Generation to Meet the 20% RPS

As more and more intermittent resources become operational, the existing uncertainties and operational challenges in the DA time frame are expected to become more serious. The risk associated with the expected uncertainties in the DA time frame could result in insufficient resources committed through the Residual Unit Commitment (RUC) Process to meet next day hourly demand.

These challenges are expected to increase with a total of 6,688 MW of installed wind resources to meet the 20% RPS goal.

4.2. California ISO Day-Ahead Load Forecast

The California ISO utilizes an Automated Load Forecast System (ALFS) to calculate its DA hourly forecast demand approximately 14 hours prior to the next operating day. As shown in Figure 4-2, for 2006, the DA hourly forecast error was greater than 1,000 MW approximately 10% of the time and similarly, the forecast error was less than -1,000 MW approximately 10% of the time. For the hours when the load forecast is deficient, the California ISO makes up this difference by committing resources through its Real-Time Unit Commitment process.

If the scheduled California ISO demand exceeds the California ISO forecast, the RUC process may identify the need to de-commit resources, but the RUC process does not automatically de-commit a resource scheduled in the Integrated Forward Market. The California ISO operator may communicate the need for de-commitment of resources with affected market participants if the scheduled California ISO demand exceeds the California ISO forecast during the Hour-Ahead Scheduling Process (HASP).

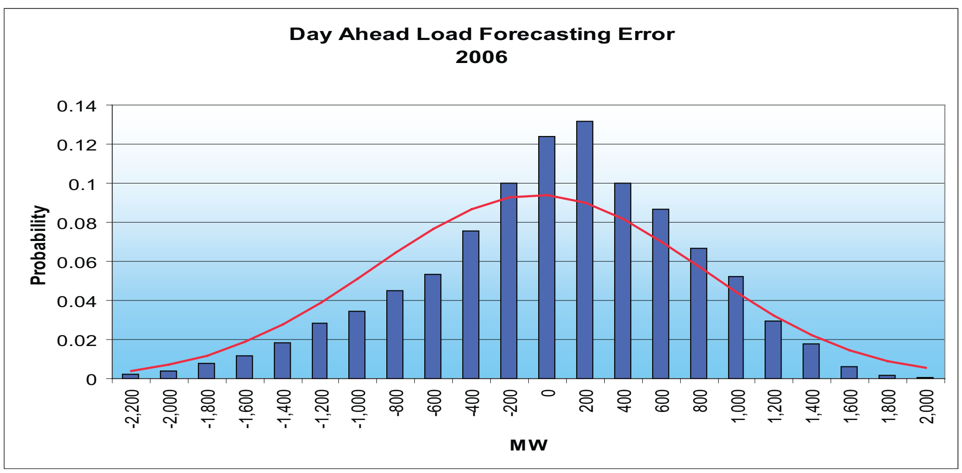


Figure 4-2: California ISO DA Load Forecast Error

4.3. Day-Ahead Scheduling Process

Load Serving Entities (LSEs) schedule energy (including the 20-minute ramps between hours) in the DA time frame to meet their forecast load as block energy schedules. The DA market closes at 1000 hours and results are published by 1300 hours the day preceding the operating day. The DA scheduling errors based on the 2006 summer months averages approximately 355 MW higher than the actual load. As shown in Figure 4-3, the Day-Ahead scheduling error mimics a normal truncated distribution curve with a standard deviation of approximately 1,700 MW. In the DA time frame, for summer 2006, there was a probability of 8% that the scheduling errors were less than -2,000 MW and a probability of 19% that they were greater than 2,000 MW. This scheduling error is assumed to be about the same when the 20% RPS target is met. The under-scheduling difference is procured through the California ISO's Residual Unit Commitment (RUC) process and takes into consideration load forecast errors and estimated generation output from wind resources. As stated above, forecasting the wind generation in the DA does not pose a reliability concern today; however, forecasting wind generation to meet the 20% RPS goal is crucial in committing non-wind resources in the DA time frame.

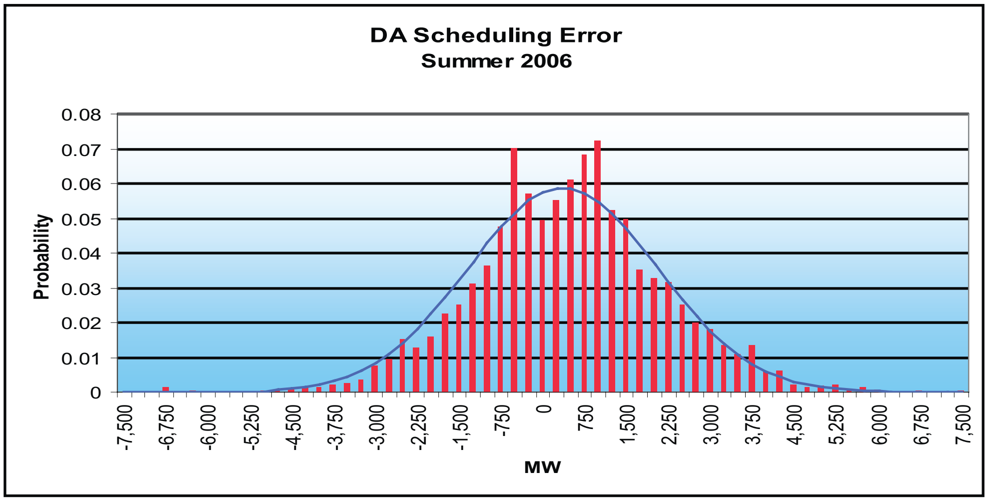


Figure 4-3: Day-Ahead Load Scheduling Error

4.4. Hour-Ahead Load Forecast Error

As mentioned previously, the California ISO forecast load is calculated by the Automated Load Forecast System (ALFS). ALFS calculates the California ISO forecast demand for several different time frames. The Hour-Ahead forecast is calculated about two-hours prior to the operating hour and subsequent half-hour forecasts are calculated for the remainder of the operating day. This process is repeated before each operating hour and each subsequent half-hour forecast is modified.

The Hour-Ahead forecast error is simply the difference between the Hour-Ahead forecast and the average hourly actual demand (excluding pump loads) for a particular operating hour. The Hour-Ahead forecast error is typically higher at higher load levels and is therefore more pronounced during the summer months. As shown in Table 4-1, during summer, the Hour-Ahead load forecast error for 2006 was between -2,657 MW and 2,103 MW with a standard deviation of approximately 900 MW. Overall, for 2006 the Hour-Ahead load forecast error was found to have a mean absolute percent error (MAPE) of 2% of actual load when averaged over a one month period. Refer to Appendix C for more details.

For this study, it was assumed that the statistical characteristics of the Hour-Ahead forecast error observed in 2006 would be the same in future years, although loads would be higher and errors tend to be higher at higher load levels. It was assumed that forecast techniques would improve over the years to compensate for errors at higher load levels.

Table 4-1: Summary of Hour-Ahead Forecast Demand Error (Actual Load – Forecast Load)

Season	Average (MW)	Min (MW)	Max (MW)	Standard Deviation (MW)	Autocorrelation [17]
Winter	-35	-3,849	1,519	652	0.69
Spring	-24	-2,101	1,931	601	0.73
Summer	-130	-3,771	2,446	900	0.89
Fall	-69	-2,628	2,081	687	0.83

Figure 4-4 shows the actual forecast errors (blue bars) compared to the theoretical error normal distribution (red line) for the summer months. Typically, during the summer months, load forecast errors tend to be the highest and were greater than 800 MW and less than -800 MW for approximately 23% of the time. Forecast errors for the other seasons can also be represented by truncated normal distribution functions.

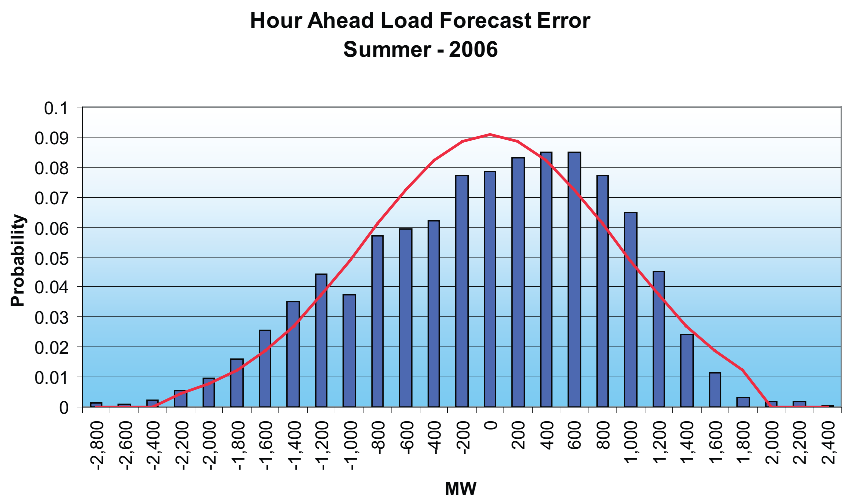


Figure 4-4: Summer Load Error Distributions vs. Theoretical Load Error Distributions

4.5. Hour-Ahead Energy Scheduling Process

With the implementation of MRTU, the California ISO will run the Hour-Ahead Scheduling Process (HASP) to lock in changes to schedules 75-minutes before the actual operating hour starts. In the actual operating day, the schedules for the wind generators in the PIRP program will also be locked in at the 75-minute point. HASP will provide 15-minute advisory schedules for internal resources and gives the California ISO the opportunity to deal with potential over-generation or under-generation conditions.

As shown in Figure 4-5, the one-hour (1hr) block energy schedule includes 20-minute ramps

17 Autocorrelation values lie between ±1 and depend on the number of observations, the standard deviation of the observations, the sample mean and the current and next observation. A value of 1 indicates that the next value has a very strong positive dependence on the previous value, while a value of -1 indicates that the next value has a strong negative dependence on the previous value. An autocorrelation value of 0 indicates that the current value gives no indication of what the next value will be.

between the hours. Since the actual load varies moment to moment during the hour, the average load could be greater than or less than the hourly schedules. Under-generation would be handled through Real-Time Unit Commitment (RTUC) or Short-Term Unit Commitment (STUC[18]) by committing short start and fast start units if it's anticipated that resources would be deficient.

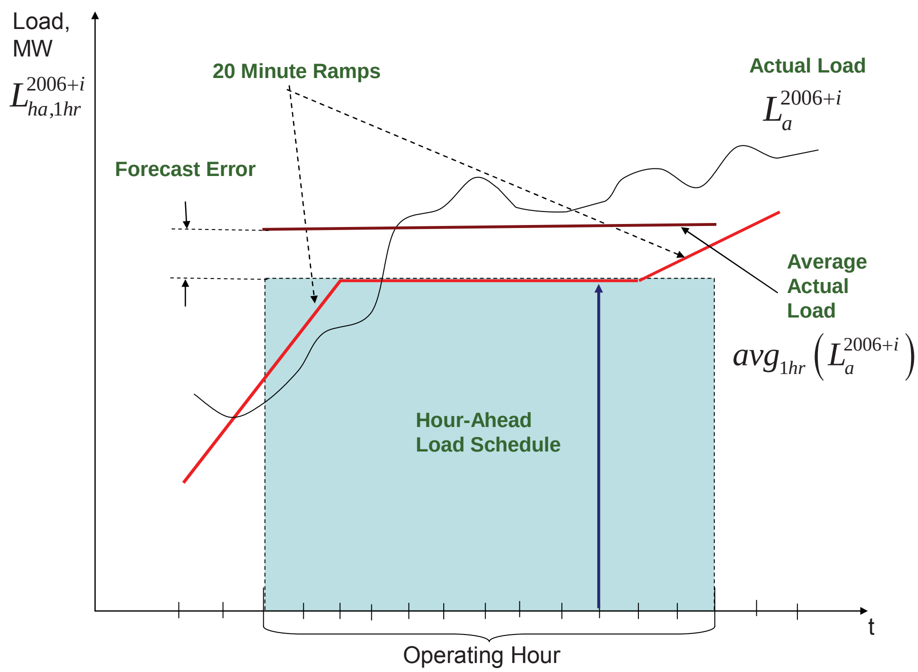


Figure 4-5: California ISO Simulated Hour-Ahead Load Schedule (Red Line) with Ramps

RTUC is a market process for committing resources and awarding additional Ancillary Services from internal resources at 15-minute intervals. The RTUC function runs every 15 minutes and looks ahead up to seven 15-minute intervals to ensure there is sufficient capacity to meet demand.

Should an over-generation condition continue in Real-Time, the Real-Time Market (RTM) will dispatch resources down using economic bids to the extent possible to relieve the over-generation condition. If the use of economic bids is insufficient, then supply curtailment will be performed in accordance with Section 34.10.2 of the California ISO Tariff.

4.6. Five-Minute Load Forecast Error

In the California ISO's Real-Time Market Systems, another forecasting tool called the Very Short-Term Load Predictor (VSTLP) utilizes the latest ALFS Half-Hour forecast and the most recent generation output from the State Estimator to forecast a 15-minute Demand Forecast and a 5-minute forecast. The 15-minute forecast is used by the Real-Time Unit Commitment

18 STUC is a reliability function for committing short and fast start units to meet the California ISO forecast demand. The STUC function is performed hourly, in conjunction with RTUC and looks ahead three hours beyond the trading hour at 15-minute intervals.

(RTUC) and the 5-minute forecast is used by Real-Time Economic Dispatch. Under MRTU, all forecast demand would include transmission losses, but pump loads would be excluded because they are scheduled.

This 5-minute forecast is run about 10-minutes before the operating interval and consists of a block of power for that time. As shown in Figure 4-6, the 5-minute load forecast error ranged from ±349 MW. The mean absolute error over the month was 0.29% and the average error over a one month interval was 1.2 MW. One standard deviation of 5-minute load forecast error is 98 MW.

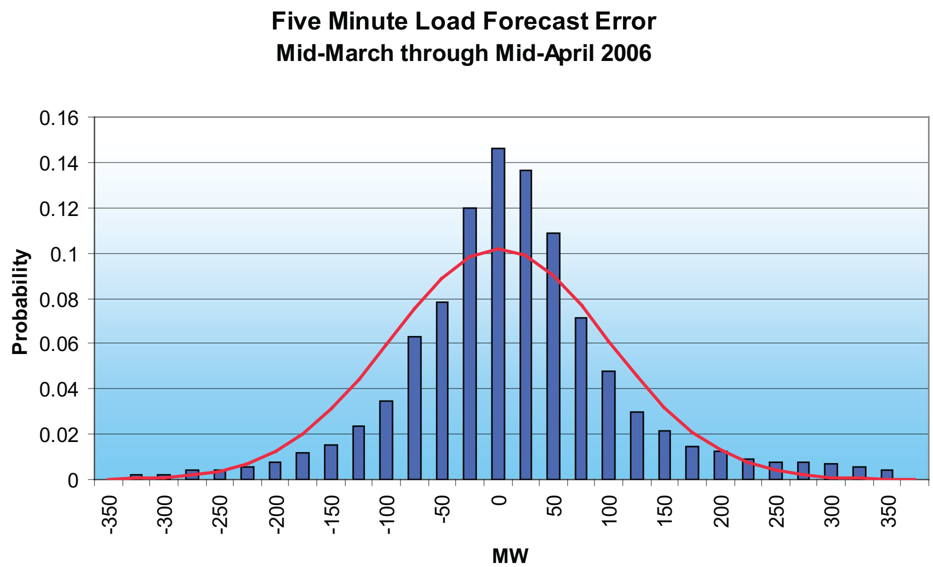


Figure 4-6. Comparison of 5-minute Load Forecast Error and Theoretical Error Distribution

The autocorrelation from mid-March through mid-April was 0.61 indicating that the next 5-minute interval has a positive dependence on the previous 5-minute error. The Real-Time load forecast is the average 5-minute load forecast that includes 5-minute ramps between the dispatch intervals.

4.7. Residual Unit Commitment (RUC)

The California ISO adjusts the hourly generation forecast either up or down for the expected wind generation. To the extent that the scheduled quantity for a wind resource in the DA is less than the quantity forecast by the California ISO, the California ISO makes a supply side adjustment in RUC by using the California ISO forecast quantity for the wind resource as the expected delivered quantity. To the extent that the scheduled quantity for a wind resource is greater than the quantity forecast by the California ISO, the California ISO makes a demand side adjustment equal to the difference between the DA schedule and the California ISO forecast quantity.

As more and more wind resources are installed, estimating the total wind output in the DA time frame creates a challenge. One of the tasks addressed in Chapter 10 of this Report is the competitive procurement of a DA Wind Generation Forecast Service that can provide the California ISO with an accurate DA wind generation forecast.

4.8. Wind Resource Forecast

Wind resources are not required to bid or schedule in the California ISO DA Market. However, when bids are scheduled in the DA Market, the ultimate quantity scheduled from the wind resource differs from the California ISO forecast deliveries from the wind resource. The California ISO uses a neural network forecasting service/software to forecast deliveries from wind resources based on the relevant forecast weather parameters that affect the output of the wind resource. The California ISO monitors and tunes forecast parameters on an ongoing basis to reduce intermittent forecast errors.

4.9. Hour-Ahead Energy Forecast for Wind Generators

The California ISO currently uses an outside service to forecast the Hour-Ahead energy production from wind generation facilities that are in the Participating Intermittent Resources Program (PIRP). The amount of wind generation in PIRP is 685 MW, which is about 25% of the total wind generation installed on the system. It is expected that the new wind generation projects in the California ISO controlled Grid will participate in the California ISO PIRP program where the Hour-Ahead forecast would be available as a PIRP requirement. The California ISO contract with the Forecast Service Provider is to provide hourly wind generation energy forecasts that have a monthly deviation of less than 12%. The hourly forecasts are actually created nearly 3 hours before the actual operating hour, so the forecast data can be used to schedule the energy in the existing Hour-Ahead market.

MRTU will shorten the PIRP scheduling process to 75 minutes before the operating hour. This should result in greater accuracy for the Hour-Ahead forecasts and schedules. Changes in the forecast methodology and the structure of the PIRP program are being considered as a task to be implemented under Chapter 10 of this Report.

An issue paper is also being developed to integrate solar (PV and Concentrated) into PIRP. The goal is to have the solar integration policy completed by early 2008.

Chapter 5 – Operations Issues: Impacts of Wind Generation on the California ISO's Ramping, Regulation and Load Following Requirements Under MRTU

This chapter primarily focuses on wind resources to meet California's RPS goal of 20% renewables in its generation mix. Small hydro, biomass and geothermal generation are very predictable resources, and their integration into the California ISO market and production levels are not anticipated to cause any operational problems. Also, since it is anticipated that less than 1,000 MW of solar resource additions would be completed by this time frame, no integration issues are envisioned. However, the integration of large amounts of wind resources into the California ISO generation mix is expected to create operating challenges because wind production is a function of wind speed and it is not dispatchable.

Wind generation output varies significantly during the course of any given day, and there is no predictable day-to-day generation pattern. One major challenge to system operators is the availability and accuracy of Day-Ahead and Hour-Ahead wind generation forecasts to ensure sufficient units are committed in the Day-Ahead and Real-Time markets for the next operating day. The California ISO also anticipates facing daily challenges to ensure adequate non-intermittent resources are available to meet multi-hour ramps to accommodate changes in system load and wind generation. These challenges are compounded when combined with large hourly ramp changes on the interties and hourly generation scheduling changes. The following analysis investigates the overall system performance under the California ISO Market Redesign and Technology Upgrade (MRTU) design and operating timelines.

The installed wind capacity in the five existing wind parks located within the California ISO-controlled Grid is approximately 2,648 MW (Solano - 327 MW, Altamont - 954 MW, Pacheco - 21 MW, Tehachapi - 722 MW and San Gorgonio - 624 MW). Although the California ISO interconnection queue for renewable resources through 2013 contains in excess of 14,000 MW of wind resources, this study assumes only an additional 3,540 MW would be installed in the Tehachapi area and an additional 500 MW would be installed in the Solano wind park for an overall total of 6,688 MW of wind generation. Major transmission upgrades must be built to accommodate these generation additions. These required transmission upgrades have already been approved by the California ISO Board of Governors and the respective Participating Transmission Owners.

5.1. Assumptions

Determining the expected ramping, load following and regulation requirements to meet the 20% goal is a function of statistical minute-to-minute actual wind generation and the determination of statistical errors associated with the California ISO load and wind forecast methodologies in the Day-Ahead, Hour-Ahead and Real-Time time frames. The major data sources and study assumptions are as follows:

1. The expected hourly wind production data was developed by AWS Truewind. The minute-to-minute variability was developed by the California ISO and AWS Truewind. The methodology used is outlined in Appendix B.

2. The overall load increase is consistent with the CEC's forecast energy growth for the state and is assumed to be 1.5% per year for the California ISO-controlled Grid.

3. The energy produced by wind resources varies as a function of wind speed.

4. The effects of wind generation on the interconnection frequency are neglected.

5. All new wind generation additions within the California ISO-controlled Grid will participate in the Participating Intermittent Resources Program (PIRP), and therefore they will be provided with a centralized Day-Ahead and Hour-Ahead forecast service.

6. The Hour-Ahead load and wind generation energy forecasts are provided — at the latest — 120 minutes before the beginning of the next operating hour.

7. The Real-Time 5-minute load forecasts are provided 7.5 minutes before the actual beginning of a 5-minute dispatch interval (or 10 minutes before the middle point of this interval).

8. Real-time telemetry from the wind resources are sent to the California ISO on a 4-second basis, similar to non-intermittent resources.

9. Pump storage **is not** considered as a part of the actual load and the load forecast. It is considered as a scheduled resource. The impact of small pumps is included in system load since they are not scheduled.

5.2. Study Methodology

The methodology developed to analyze the wind generation effect is based on a mathematical model of the California ISO's actual scheduling, Real-Time dispatch, and regulation processes and their timelines. Minute-to-minute variations and statistical interactions of the system parameters involved in these processes are depicted with sufficient details to provide a robust and accurate assessment of the additional capacity, ramping and ramp duration requirements that the California ISO regulation (AGC) and load following (ADS) systems will be facing when the 20% RPS is achieved.

In order to represent the California ISO's Hour-Ahead scheduling process, the probability distributions of the total California ISO load forecast and total California ISO wind generation forecast errors[19] were studied for the year 2006. Refer to Appendices C & E. It has been found that these errors have a close normal probability distribution with negligible average forecast error and significant autocorrelation between the subsequent forecasts. The wind generation forecast statistical parameters were discussed with and approved by AWS Truewind Company for each season of a year. A special truncated normal distribution random generator with controllable standard deviation and autocorrelation was designed to simulate the sequences of random forecast errors for each study season. The Hour-Ahead schedules for the system load and wind generation were created for each operating hour based on the actual predicted load and wind generation curves as well as the simulated Hour-Ahead forecast errors. Twenty-minute ramps were added between the subsequent operating hours.

In order to simulate the Real-Time dispatch process, the Real-Time load forecast error was also analyzed and simulated similarly to the Hour-Ahead load forecast. The randomly generated error was subtracted from the actual 5-minute averages of the system load to simulate the Real-Time load schedules. Five-minute ramps were added to the simulated load schedule curves. The Real-Time wind generation curves were modeled by applying the persistence model. This model assumed that the wind generation within each 5-minute dispatch interval would be the same as it was 8 minutes before the beginning of this interval.[20]

The load-only impact on regulation was considered as the minute-to-minute difference between the simulated Real-Time load schedule and the actual load.

The wind generation impact on regulation was simulated in three steps. First, the difference between the actual wind generation and the simulated wind generation schedule was evaluated for every minute. Second, the combined impact of the system load and wind generation on regulation was simulated as the difference between the load-only impact curve and wind generation impact curve. This approach fully depicts the statistical interactions between the load and wind generation unscheduled changes. Third, the additional impact of wind was calculated as the difference between the combined impact and the load-only impact.

The load-only and combined load and wind generation impact curves were analyzed using the swinging door algorithm[21] to calculate the ramp and ramp duration requirements for each minute in the study season. Please refer to Appendix A for a detail description of the algorithm.

5.3. Conclusions

1. Integrating 20% renewables in the California ISO-controlled Grid is operationally feasible; however, several additions to the operational practice will be required (see Recommendations for details). Without these recommended changes, there may be significant effects on the market clearing prices and unit commitment costs.

19 An assumption was that a comprehensive Hour-Ahead wind generation forecast would be available for the California ISO, Scheduling Coordinators and IOUs and that it would be incorporated in the Hour-Ahead scheduling processes. It is expected that the new wind generation projects in California will participate in the California ISO PIRP program where the Hour-Ahead forecast would be available as a PIRP requirement.

20 This means that the Real-Time wind generation forecast is not available.

21 The swinging door algorithm helped to build a meaningful sequence of ramps needed to provide an adequate regulation service. The algorithm is based on a user-specified tolerance of following the ramps.

2. The 20% renewables requirement is expected to increase the 3-hour morning ramp by 926 MW to 1,529 MW and the 3-hour evening ramp by 427 MW to 984 MW depending on the season. (Refer to Table 5-1.)

3. The California ISO regulation capacity requirements will increase noticeably during certain hour ranges. The increase is explained by increasing inaccuracy of the persistence model used in this study for the Real-Time wind generation forecast, which reflects the current approach used by the California ISO's Real-Time Dispatch. Table 5-5 summarizes the study results (maximum expected values) based on an Hour-Ahead wind generation forecast error of 7% to 9% depending on the season. Regulation capacity requirements decrease with better wind forecasts.

4. The California ISO regulation ramping requirements to meet the 20% RPS is expected to increase by about ±10 to ±25 MW/min. These increases will affect AGC ramps up to five-minutes long. (Refer to Table 5-6.)

5. The California ISO would also require a significant increase in the supplemental energy stack to meet intra-hour load following needs. The increase is explained by the fact that the Hour-Ahead wind generation forecast error (standard deviation is evaluated as 7-9% of the total installed wind generation capacity) becomes comparable with the Hour-Ahead load forecast error (standard deviation is 600-900 MW). These load following capacity requirements decrease with better wind forecast. Please refer to Table 5-4 for a comparison of load following capacity requirements when a 5% wind forecast error is used.

6. The California ISO maximum load following ramping requirements to meet the 20% RPS is expected to increase by about ±30 to ±40 MW/min. These increases will affect ADS ramps up to 20-30 minutes long. (Refer to Table 5-3.)

5.4. Recommendations

1. Implement a state-of-the-art wind forecast service for all wind generator energy production within the California ISO-controlled Grid. This includes Day-Ahead, Hour-Ahead and Real-Time wind generation forecasts. These forecasts will be crucial for the unit commitment, scheduling and dispatch processes in the Day-Ahead, Hour-Ahead and Real-Time time frames.

2. Incorporate the Day-Ahead and Hour-Ahead wind generation forecasts (block energy schedules) into the California ISO's and the SCs' scheduling processes. The Day-Ahead and Hour-Ahead schedules must be based on the forecast wind generation values.

3. Integrate the Real-Time wind generation forecast (average wind generation for 5-minute dispatch intervals) with the Real-Time unit commitment and MRTU dispatching applications.

4. Develop a new ramp forecasting tool to help system operators anticipate large energy ramps — both up and down — on the system. The longer the lead time for forecasting

a large ramp, the more options the operators have to mitigate the impact of the ramp. One of the proposed tasks under Chapter 10 of this Report addresses the creation of the ramp forecasting tool.

5. Change the California ISO generator interconnection standards to require compliance of all intermittent resources with the interconnection rules established for the PIRP. These rules include installing meteorological towers and DPG telemetry systems to communicate the 4-second meteorological and production data from wind parks to the California ISO. This data needs to be integrated into the California ISO's forecasting software.

6. Implement a procedure where the California ISO dispatcher can send dispatch notices to wind generation operators and require them to implement pro-rata cuts in their energy production. During over-generation periods, when dispatchable generation plants are already operating at their minimum levels, the California ISO needs to have an ability to curtail wind generation on an as-needed basis.

7. Analyze the impact of solar power intermittency with load and wind generation intermittency.

8. Evaluate technological changes that can facilitate the integration of large amounts of intermittent resources. For example, evaluate the benefits of participating in a wider-area arrangement like ACE sharing or Wide Area Energy Management system.[22]

9. Study the impact that additional cycling (additional start ups) and associated wear-and-tear issues; dispatches below the maximum unit capacity; and associated additional costs and environmental impacts on conventional generation due to the integration of large amounts of intermittent resources. Address whether improvements can be made to the California ISO's Scheduling, Real-Time Dispatch and Regulation systems that will minimize the impacts on conventional units.

10. Encourage the development of new energy storage technology that facilitates the storage of off peak wind generation energy for delivery during on-peak periods.

11. Include changes in Resource Adequacy standard to require more generation with faster and more durable ramping capabilities that will be required to meet future ramp requirements.[23]

12. Include changes in Resource Adequacy standard to require additional quick start units that will be required to accommodate Hour-Ahead forecast errors and intra-hour wind variations.

22 Principles of the Wide Area Energy Management system are currently under design at Pacific Northwest National Laboratory (PNNL). The project is sponsored by Bonneville Power Administration. The California ISO is a participant in this project.

23 The California ISO is currently participating in a California Energy Commission sponsored project with PNNL and Oak Ridge National Laboratory on the value of fast regulation resources.

5.5. Day-Ahead Forecast and Scheduling Process

Day-Ahead (DA) load forecast errors coupled with DA wind generation forecast errors can have a significant impact on the Residual Unit Commitment process. This problem could get worse since wind resources are not required to bid in the DA market. The major risk of forecast errors in the Day-Ahead time frame is that insufficient resources will be committed to meet the next day's load. Additional work that needs to be done is outlined in chapter 10.

5.5.1. Day-Ahead load forecast

The Day-Ahead hourly load forecast is calculated approximately 14 hours before the start of the operating day. Based on 2006 data, the Day-Ahead forecast errors can vary from ±3,000 MW with a standard deviation of 858 MW.

With the exception of pump loads, which are scheduled, the California ISO peak load demand is proportional to temperature. Historical load and temperature data for several weather stations within the California ISO-controlled Grid are shown in Figure 5-1. As the average temperature in the California ISO-controlled Grid exceeds 100° F, the load forecast varies significantly for each degree change in average temperature. When the average temperature is above 100° F, a forecast error of one degree could result in the California ISO load forecast potentially being understated or overstated by approximately 980 MW (Southern California Edison 490 MW/°F; Pacific Gas & Electric 399 MW/°F and San Diego Gas & Electric 91 MW/°F.)

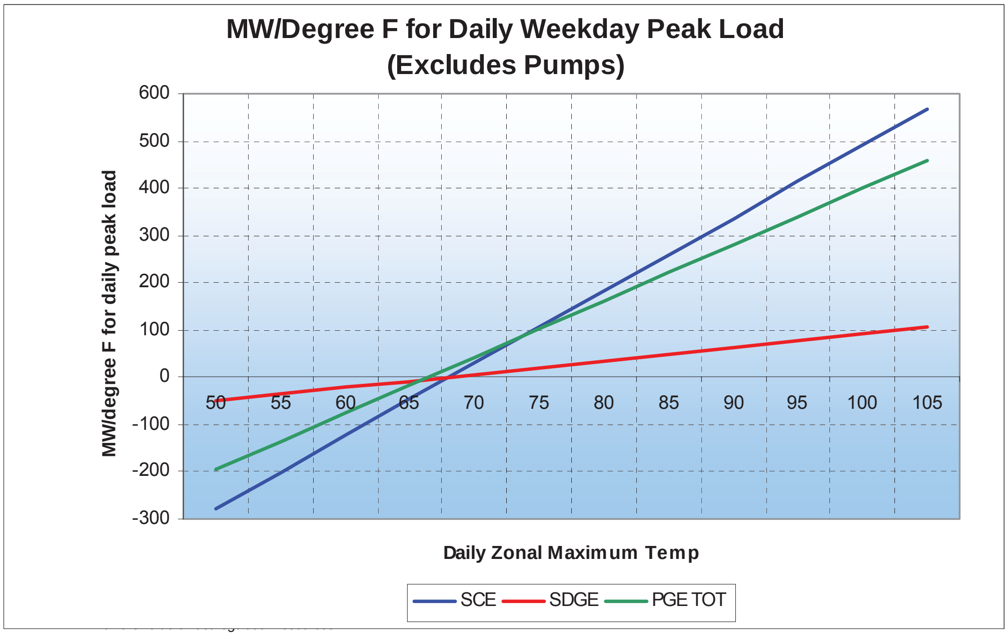


Figure 5-1: Temperature vs. Peak Load Variation

5.5.2. Wind generation Day-Ahead forecast and schedules

Wind resources are not required to bid or schedule in the California ISO Day-Ahead Market (DAM). However, when bids are scheduled in the DAM, the quantity scheduled typically differs from the California ISO forecast deliveries. To meet the 20% RPS, with the installed capacity of wind generation at about 6,688 MW, the DAM could clear at significantly lower levels for next day operation based on self schedules and economic bids from Scheduling Coordinators, which may or may not include wind generation forecast.

To minimize DA forecast errors, the California ISO is preparing a bid specification for procurement of a Day-Ahead wind generation forecast service. An RFP is slated to be released in the fall of 2007 and a service provider chosen by the end of the year.

5.5.3. Day-Ahead Market

Bidding into the DAM is closed at 1000 hours and results are published by 1300 hours on the day preceding the operating day. Scheduling Coordinators (SCs) submit bids (for supply and demand) for each resource to be used in the DAM. Ancillary Service (AS) bids are also submitted in the DAM, which is optimized in conjunction with energy bids to minimize the total bid cost of clearing congestion, balancing energy supply and demand, and reserving AS. Additionally, in the DAM, the California ISO runs a Residual Unit Commitment Program (RUC) to ensure that sufficient capacity is committed, on-line and available for dispatch in Real-Time to meet the California ISO forecast for each trading hour of the operating day.

While RUC commits resource capacity from long start and short start units to meet California ISO forecast of demand, RUC does not automatically de-commit resources in cases where the DA schedules exceed the load forecast. When more generation is anticipated than load, exceptional dispatches may be necessary to resolve over-generation conditions. Such actions may require de-committing resources. Should over-generation conditions propagate into Real-Time and dispatchable generators are already operating at their minimum levels, the California ISO needs to have the ability to curtail wind generation, as necessary, to maintain reliability.

5.6. Wind vs. Actual Load on a Typical Hot Day

Typically, during the summer, wind generation peaks when the total system load is low and is at its lowest production levels when the total system load is high. Figure 5-2, shows the variation of average hourly wind generation and the actual wind generation (red dots) at the time of the daily system peak load during the week with the hottest average temperatures within the California ISO-controlled Grid in 2006.

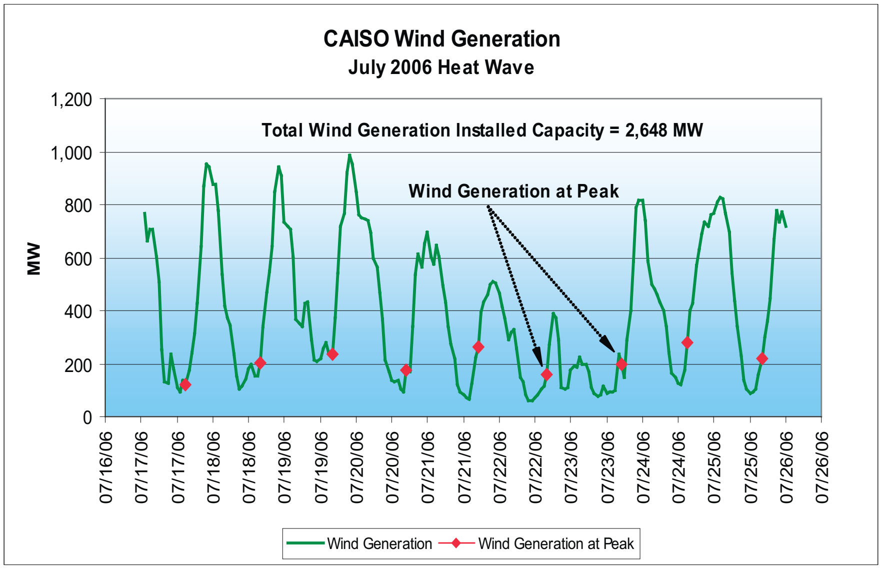


Figure 5-2: California ISO Wind Generation during the 2006 Heat Wave

Although the daily summer pattern "high load and low wind" is predictable, the actual hourly wind generation output can vary significantly from one day to the next. Figure 5-3 shows the actual wind generation for May 2006 compared to the expected wind generation to meet the 20% RPS. As shown, the hourly generation varied significantly in 2006, and without dependable wind generation forecasts, it's difficult to predict the expected wind generation in any given hour. For example, to meet the 20% RPS, the wind generation is expected to vary between 1,400 MW and 6,000 MW during hour ending 19.

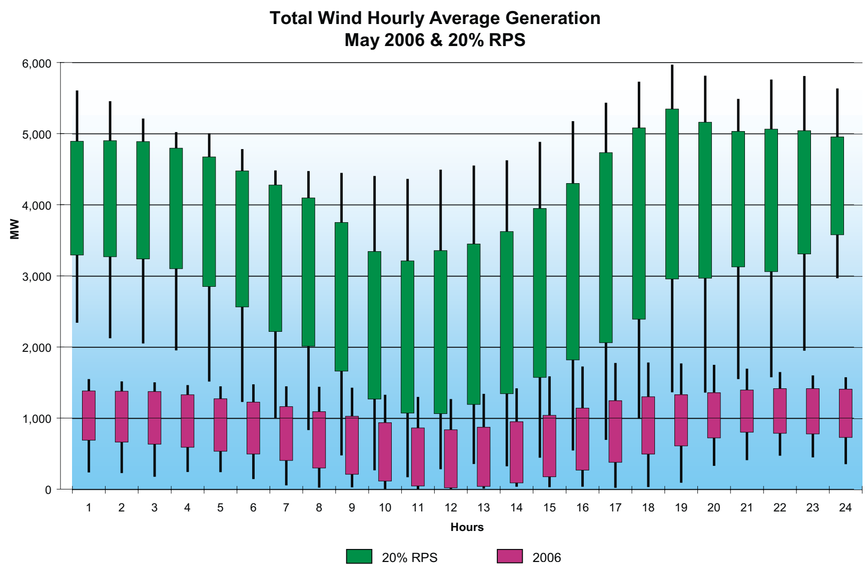


Figure 5-3: Actual 2006 Hourly Wind Generation vs. Expected 20% RPS Hourly Wind Generation

Note: The colored bars represent one standard deviation from the mean. The top of each vertical line shows the hourly maximum and the bottom shows the minimum expected generation for that hour.

5.7. Multi-Hour Seasonal Ramping Requirement

With an expected installed wind generating capacity of 6,688 MW, the minute-to-minute and hourly variability on the system is expected to increase significantly. Both the California ISO load demand and wind generation characteristics vary by season. In 2005 and 2006, the maximum wind production occurred in late spring (May) followed by the first month of the summer (June). By the time the 20% RPS is met, a combination of load increase in the morning hours and a decrease in wind production during Hour Ending (HE) 8 through HE10 in the summer months could result in the need to commit about 12,664 MW of capacity in the Day-Ahead Market or have adequate short start[24] and fast start[25] resources available to commit in Real-Time. Similarly, a combination of load drop-off in the evening hours and an increase in wind production during HE22 through HE24 could result in the need to curtail about 13,500 MW of generation over a 3-hour period.

5.7.1. Spring months

During the spring months (March, April and May), the California ISO load characteristic has a unique shape that shows two daily peaks, one occurring around HE13 and the second around HE21. Figure 5-4 shows the average hourly system load, average wind generation and solar generation during the course of a typical day. As shown, the total wind generation starts decreasing after midnight and reaches its minimum production level around midday, just as the system experiences the first peak of the day. Beginning around HE13, the wind generation starts ramping up while system load typically drops off.

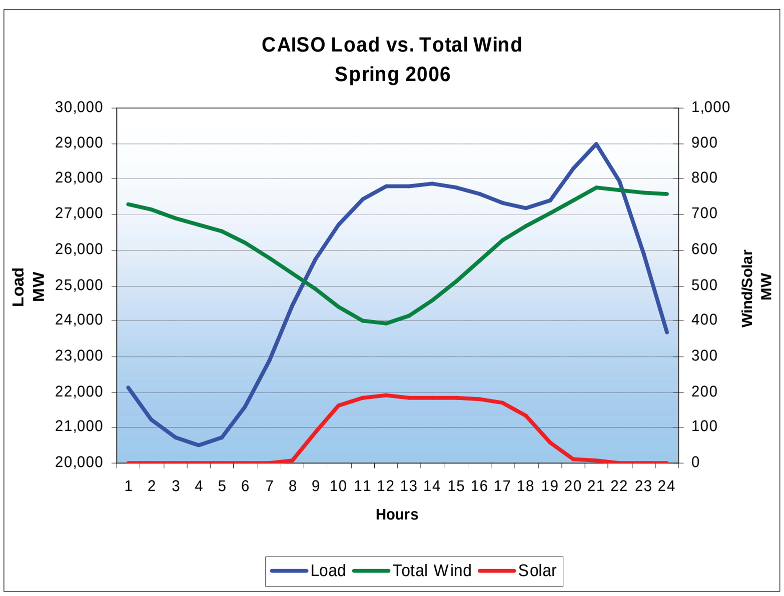


Figure 5-4: Actual System Load, Wind Generation and Solar Generation for Spring

24 Short Start: Generating units that have a cycle time less than 5 hours (start-up time plus minimum run time is less than 5 hours), have a start-up time less than two hours and can be fully optimized with respect to this cycle time

25 Fast Start: Start-up time is within the time horizon for any given RTUC (from 60 to 105 minutes).

As system load increases towards the second peak of the day, wind generation helps in offsetting some of the energy required to meet the increase in load. As system load begins dropping after the daily peak, wind is typically at its highest generation level. During the 2006 spring months, the average hourly wind generation peaked at about 775 MW.

As shown in Figure 5-5, the maximum hourly deviations occurred during HE19 and varied from -225 MW to 340 MW. After full build out, the actual generation level is expected to vary between 125 MW and 5,950 MW. The largest hourly deviation is still expected to occur during HE19 and can vary from -1,150 MW to 1,480 MW, which coincides with the system load increase and the increase in wind generation.

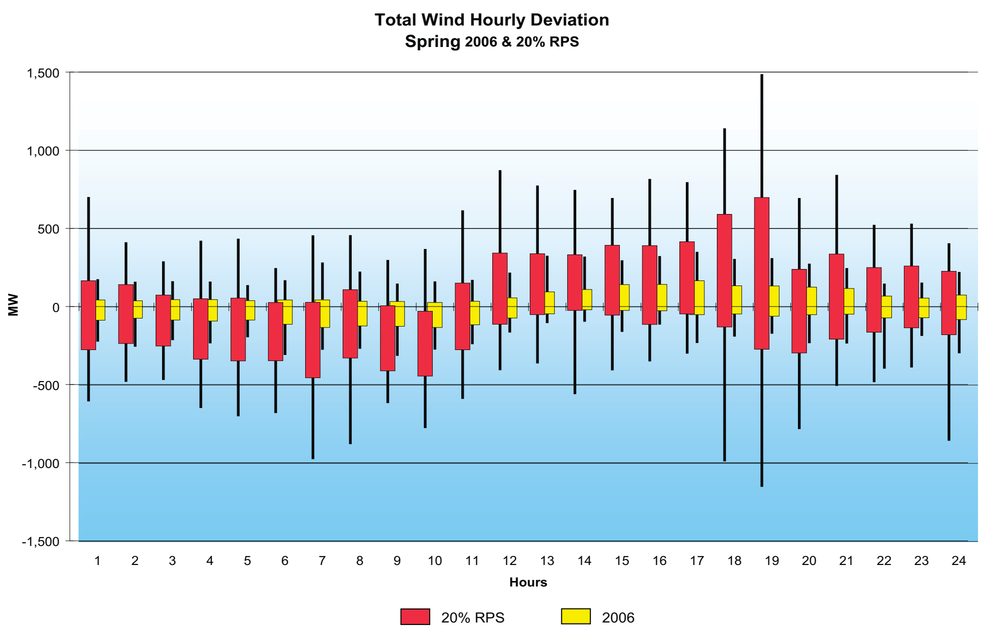


Figure 5-5: Spring 2006 Actual Hourly Variations vs. Expected Hourly Deviation with 20% RPS Integration

Note: The colored bars represent one standard deviation from the mean. The top of each vertical line shows the hourly maximum and the bottom shows the minimum generation for that hour.

5.7.2. Spring — morning and evening multi-hour ramps

During the 2006 spring months, the maximum morning load buildup from HE7 through HE9 was approximately 6,170 MW, while the maximum wind generation decreased by approximately 690 MW. Figure 5-6 shows the maximum increase/decrease for each of the hours in the 3-hour ramps. It is expected that with the 20% RPS, the morning load buildup would increase to approximately 6,847 MW. During this same three-hour window, wind generation is expected to decrease by about 1,646 MW, which would result in the need to increase generation by approximately 8,493 MW. This increase in resources would have to be committed in either the Day-Ahead Unit Commitment process or through the Real-Time Unit Commitment process. Any deficiency would have to be met through load following and regulation.

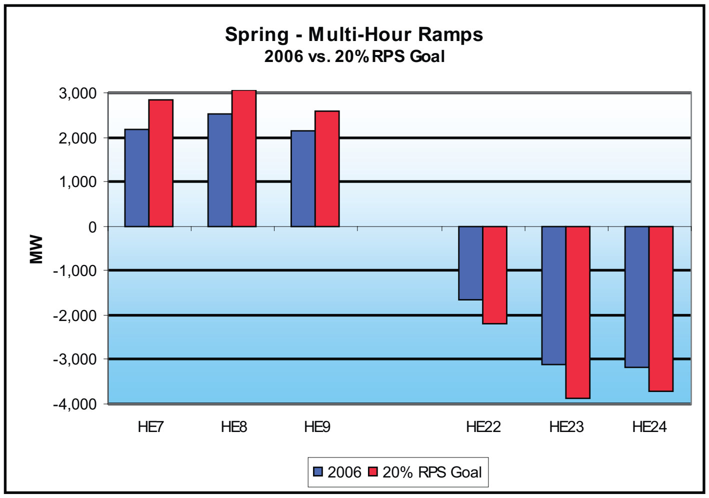


Figure 5-6: Actual Net Hourly Ramps

During the evening hours (HE22 through HE24), the system load typically decreases while wind generation is at its highest of the day. In 2006, the maximum reduction in load was about 7,660 MW, while the maximum increase in wind generation was about 301 MW. With the 20% RPS build out, the total system load is expected to decrease by about 8,502 MW during these three hours and wind generation could increase by about 1,286 MW. These changes in load and wind generation could require decreasing non-wind resources by about 9,788 MW.

5.7.3. Summer months

The California ISO load typically peaks during the summer months (June, July and August). Likewise, the peak production level from wind generation is also highest during the summer months. Unfortunately, the highest load demand periods coincide with low levels of wind production, and low levels of load demand coincide with maximum levels of wind production.

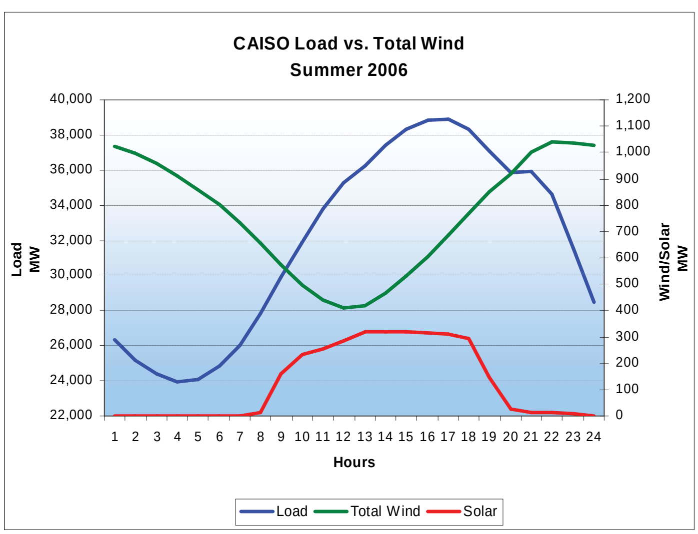


Figure 5-7: Actual System Load, Wind Generation and Solar Generation for Summer 2006

As shown in Figure 5-7, the maximum load variations are more noticeable during the summer months. The daily load cycle reaches a minimum around HE4 and peaks around HE17. After the peak demand of the day is realized, load gradually decreases, while wind production continues to increase up to about HE22 and remains more or less constant through midnight. After midnight, wind production gradually decreases and reaches its lowest level of production around midday. Although small in capacity, the solar generation profile coincided with that of load and could be beneficial in alleviating some of the expected ramping concerns as more of California's RPS goals are met with the integration of solar resources.

During the 2006 summer months, maximum wind generation occurred between HE20 through HE24 and averaged about 1,100 MW, while the minimum levels occurred around midday and averaged approximately 400 MW. This pattern is expected to continue. After the 20% RPS build out, it is expected that the hourly variations would be between -1,140 MW and 1,820 MW with a standard deviation of approximately 390 MW.

5.7.4. Summer — morning and evening multi-hour ramps

During the 2006 summer months, the maximum morning load buildup (HE8 through HE10) increased by approximately 9,509 MW, while the maximum reduction in wind production was approximately 582 MW, an overall increase of about 10,091 MW. Figure 5-8 below, shows the net average increase for each operating hour within the three-hour ramps. It is expected that the 20% RPS build out would result in the maximum morning load buildup increasing to approximately 10,553 MW, while wind generation is expected to decrease by about 2,111 MW for a net increase of approximately 12,664 MW.

During HE22 through HE24, the system load typically decreases. In 2006, the maximum load reduction was 10,179 MW, while the maximum increase in wind generation was about 411 MW. It is expected that the maximum system load could decrease by about 11,297 MW during these three hours and wind generation could increase by about 838 MW. Overall, it is expected that the California ISO needs to be able to run back generation to the extent of 12,135 MW during these three hours.

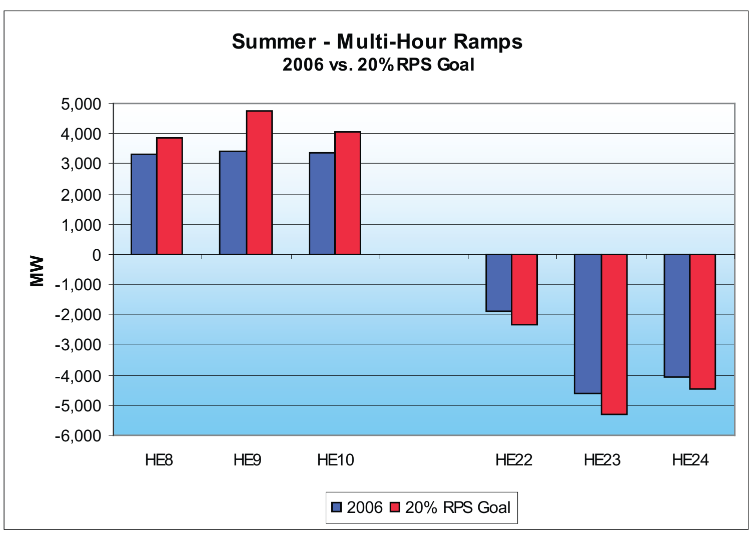


Figure 5-8: Actual Net Hourly Ramps

5.7.5. Fall months

During the fall months (September, October & November), the load profile looks similar to the summer profile in that it has one distinct peak, which occurs around HE 20. The peak load demand in the fall months averaged about 65% of the summer peak. In the fall, wind production levels show a significant decrease from the levels observed during summer. As shown in Figure 5-9 below, the daily load cycle reaches a minimum around HE4 and peaks around HE20. The daily peaks typically coincide with the increase in wind production. However, as load drops off after the daily peak, the wind generation levels continue to increase through midnight. During the fall 2006, the maximum wind generation occurred between HE20 through HE24 and averaged about 575 MW or 22% of installed wind capacity. This pattern is expected to continue, except the peak levels of production could be as high as 5,100 MW with the 20% RPS build out. In 2006, actual wind production varied from almost zero to about 1,500 MW. It is expected that the hourly variations would be between -860 MW and 1,290 MW with a standard deviation of approximately 400 MW.

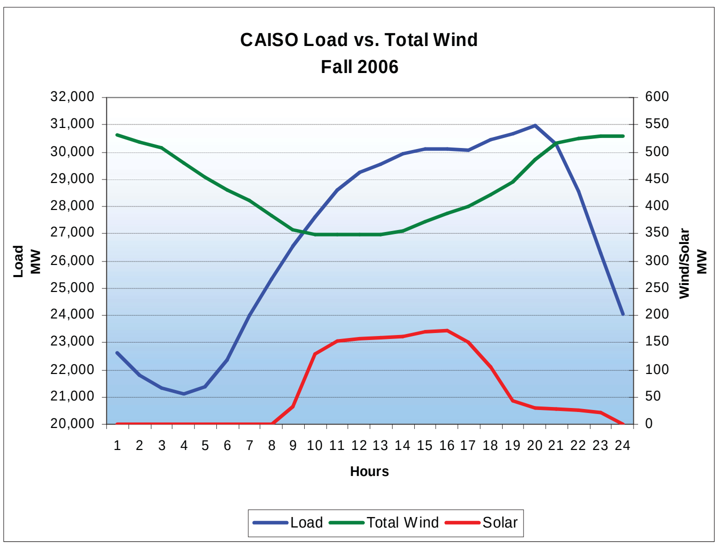


Figure 5-9: Actual System Load, Wind Generation and Solar Generation for Fall 2006

5.7.6. Fall — morning and evening multi-hour ramps

During the 2006 fall months, the largest morning load buildup typically occurs between HE7 and HE9 and the maximum increase was approximately 6,759 MW. The maximum decrease in wind generation was about 471 MW during this time. Figure 5-10, shows the net average increase for each operating hour within the three-hour ramps. After the 20% RPS build out, the maximum morning load buildup could increase to approximately 7,501 MW. Wind generation is expected to decrease by about 1,494 MW, for a net increase of approximately 8,995 MW. During the 2006 evening hours (HE22 through HE24), the maximum decrease in system load was 11,213 MW, while the maximum increase in wind generation was about 298 MW. After the 20% RPS build out, the maximum reduction in load could be about 12,445 MW, while the maximum increase in wind production could be about 1,038 MW during the evening hours. It is expected that the California ISO needs to be able to run back generation to the extent of 13,483 MW during these three hours.

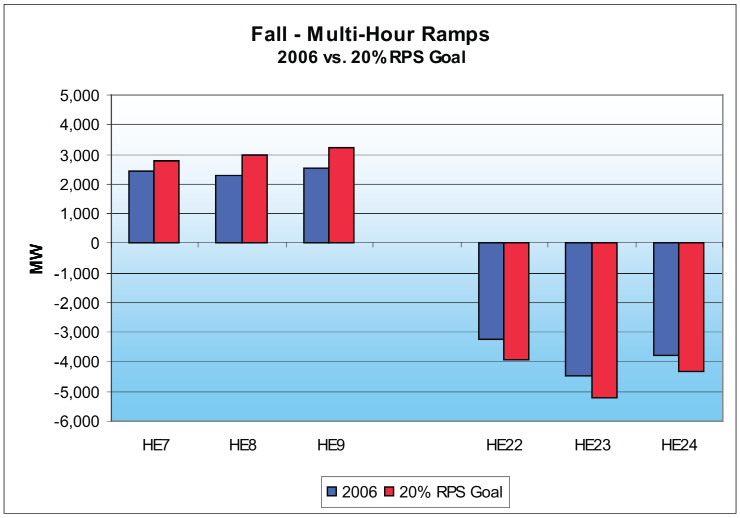


Figure 5-10: Actual Net Hourly Ramps

5.7.7. Winter months

During the winter months (December, January & February), the load profile looks similar to the spring in that it has two distinct peaks, one occurring around midday and the second occurring around HE19. Like the spring and fall months, the peak load demand in winter typically averages about 60% to 70% of the summer peak demand. As shown in Figure 5-11, the wind production level is the lowest during the winter months, but also follows the typical pattern whereby the peak generation occurs around midnight and the minimum generation occurs around HE10. During the 2006 winter months, the maximum wind generation occurred between HE20 through HE24 and averaged about 325 MW or 12.5% of installed capacity. This pattern is expected to continue with the build out, except the peak levels of production could be as high as 4,460 MW. It is expected that the hourly variations would be between -1,425 MW and 790 MW with a standard deviation of approximately 340 MW.

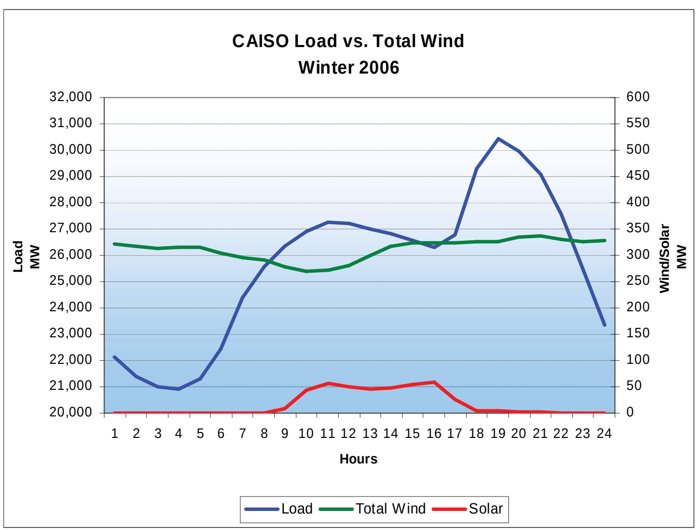


Figure 5-11: Actual System Load, Wind Generation and Solar Generation for Winter 2006

5.7.8. Winter — morning and evening multi-hour ramps

During the 2006 winter months, the maximum morning load buildup (HE6 through HE8) was approximately 6,609 MW, while the maximum wind reduction was about 370 MW. Figure 5-12, shows the net average increase/decrease for each operating hour. After the 20% RPS build out, the morning load buildup is expected to increase to about 7,335 MW, while the maximum wind reduction could be about 1,296 MW. During the 2006 evening hours (HE22 through HE24), the maximum system load reduction was about 7,589 MW. The increase in wind generation during this time was about 267 MW. To meet the 20% RPS, the total system load could decrease by about 8,423 MW and the wind production could increase by about 870 MW during these three hours. Overall, it is expected that the California ISO needs to be able to curtail generation to the extent of 9,293 MW between HE22 through HE24.

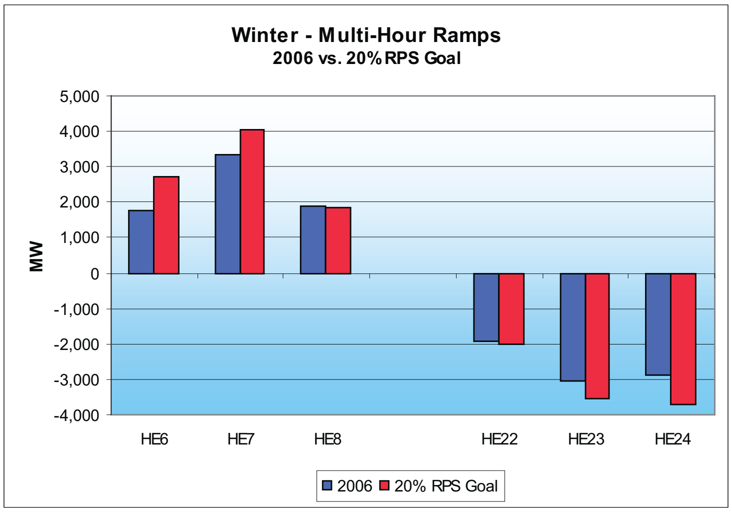


Figure 5-12: Actual Net Hourly Ramps

5.7.9. Summary of multiple hour ramp requirements

Table 5-1 shows the increase in the three-hour morning and three-hour evening ramps between 2006 and after the 20% RPS build out. The "Change due to intermittency" column only shows the increase due to wind variability between the two time frames.

Table 5-1: Summary of Multi-Hour Ramps

Seasons	2006 Morning Ramps MW	20% RPS Expected Morning Ramps MW	Change due to Intermittency MW	2006 Evening Ramps MW	20% RPS Expected Evening Ramps MW	Change due to Intermittency MW
Spring	6,860	8,494	955	7,962	9,788	984
Summer	10,090	12,664	1,529	10,589	12,135	427
Fall	7,229	8,995	1,023	11,511	13,483	740
Winter	6,979	8,631	926	7,856	9,293	603

Note: Morning Ramps – Spring & Fall: HE7 through HE9; Summer: HE8 through HE10; and Winter: HE6 through HE8. Evening Ramps – All seasons: HE22 through HE24

5.8. California ISO Scheduling and Load Balancing Processes

Wind generation impact analysis methodology is based on a mathematical model of the actual California ISO's scheduling, Real-Time dispatch, and regulating processes and their timelines. In order to model the scheduling process, the probability distributions of the total California ISO load forecast errors and total California ISO wind generation forecast errors are necessary inputs to the model.

Figure 5-13 illustrates how the generators in the California ISO-controlled Grid are scheduled and dispatched. Day-Ahead load forecasts are calculated approximately 14 hours prior to the next operating day.

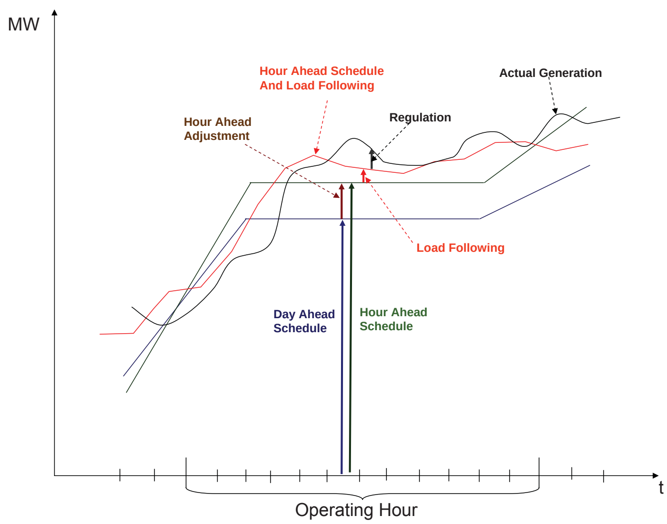


Figure 5-13: California ISO-controlled Grid Scheduling Process

Hour-Ahead load forecasts are block energy hourly schedules including the 20-minute ramps between the hours. Hour-Ahead schedules are provided 75 minutes before the actual beginning of an operating hour. The load forecast used for the Hour-Ahead scheduling process is provided 2 hours before the beginning of an operating hour. Refer to Appendix B. The difference between the Day-Ahead and Hour-Ahead schedules constitute the required generation adjustment, which is done through the California ISO's Short Term Unit Commitment and Real-Time Unit Commitment software applications. The California ISO runs its Real-Time Economic Dispatch program every 5 minutes to meet the forecast of the imbalance requirement between generation and load. This is shown in Figure 5-13 as the area below the red line and the Hour-Ahead schedule and is labeled as "Load Following." The area between the load following and the actual generation is met through regulating reserve, which is dispatched through Automatic Generation Control. A detailed description of the dispatch of regulating reserve is provided under section 5.10. "Regulating Requirement."

5.8.1. Real-Time Dispatch — load following

Real-Time dispatch or load following[26] is automatically conducted by the California ISO's MRTU applications using 15-minute intervals for Real-Time Unit Commitment and 5-minute intervals for Real-Time Economic Dispatch. Load following is not a FERC-defined Ancillary Service. Generally, the objective of a Real-Time Market (RTM) is system balancing and load following on a forward-looking basis, above and beyond the normal function of the Automatic Generation Control (AGC). Since the RTM is forward-looking, AGC is mainly a control rather than an energy service. As AGC units depart from their Dispatch Operating Point (DOP) responding to frequency and net interchange deviations, they temporarily supply or consume balancing energy. The Real-Time Economic Dispatch function dispatches ahead of AGC, while AGC resolves shorter term imbalances. The California ISO buys or sells balancing energy at regular intervals from or to resources that participate in the RTM, allowing AGC units to move closer to their DOPs.

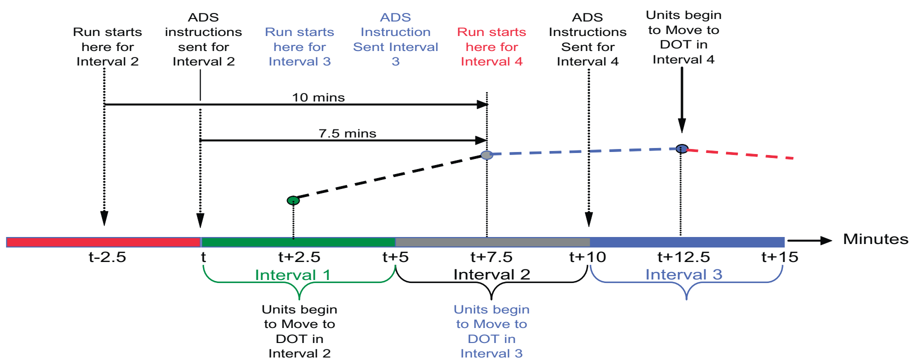


Figure 5-14: MRTU Timeline for 5-Minute Dispatch

As shown in Figure 5-14, the Real-Time Economic Dispatch software normally runs every 5-minutes starting at approximately 7.5 minutes prior to the midpoint of the next dispatch interval and produces a Dispatch Instruction for energy for the next dispatch interval and advisory Dispatch instructions are issued for as many as 13 future dispatch intervals over the RTD optimization time-horizon of 65 minutes. The generation dispatch for the next operating interval is referred to as instructed deviation from schedules caused by Real-Time energy dispatch. Generation and load information used for this dispatch interval is at least 10-minutes old. Generating units start to move 2.5-minutes before the interval begins and are expected to reach their dispatch operating point in 5-minutes. During this 5-minute interval, all deviations are met by regulation.

5.8.2. Load following requirements

Although the morning load buildup is steadily increasing during the morning hours, the actual ramping requirement for Real-Time operation varies in both the positive and negative directions for any given hour. This is due to many factors, including the hourly block generation and load

26 Load following is an instructed deviation from schedule caused by the Real-Time (or supplemental) energy dispatch. The desired changes of generation are determined in Real-Time for each 5-minute dispatch interval 7.5 minutes before the actual beginning of the interval.

schedules submitted in the California ISO market systems. The forecast load for any hour is actually the forecast for mid-hour, while most generators are expected to be at their scheduled operating points 10-minutes into the operating hour.

Generating units are typically moved over a 20-minute ramping period between hours to meet their next hourly schedules. Economics, ramp rates and actual operating conditions dictate which units are moved to meet their next hour's schedules. While some generators are dispatched to meet their next hour's schedules, other generators may have to be curtailed on a 5-minute basis through the California ISO's Real-Time Economic Dispatch system to maintain a balance between generation and 5-minute load forecast. The blue shaded area in Figure 5-15 below shows the load following requirements based on 5-minute Real-Time Economic Dispatch.

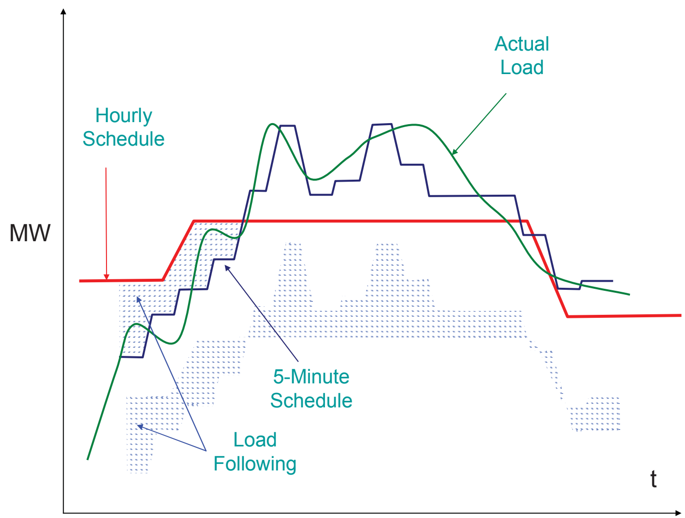


Figure 5-15: Load Following Requirement Shown as Blue Shaded Area

5.8.3. Load following capacity requirements

Seasonal simulation results for load following capacity requirements, ramping requirements and ramp duration are shown in Figures 5-16, 5-17 and 5-18 respectively. As shown in Figure 5-16, the California ISO would require a significant increase in the supplemental energy stack to meet intra-hour load following needs. The increase is explained by the fact that the Hour-Ahead wind generation forecast error (standard deviation is evaluated as 7% to 9% of the total installed wind generation capacity) becomes comparable with the Hour-Ahead load forecast error (standard deviation is 600 MW to 900 MW). Figure 5-16 also shows the load following capacity requirements for all hours of a typical summer day. Refer to Appendix B.

The green line represents the minimum and maximum load following capacity requirements due only to wind for 2006. The red line shows the requirement due solely to wind to meet the 20% RPS. As shown, the maximum upward capacity requirement of 3,500 MW occurs during HE3 and HE11. Also, the maximum downward capacity requirement of 3,450 MW occurs during HE24. The hourly upward increase is simply the difference between the top of the red arrow and the top of the green arrow for each hour. The maximum upward increase of 800 MW occurs during HE3 (3,500-2,700). The maximum downward increase of 600 MW (3,050-2,450) occurred in HE22.

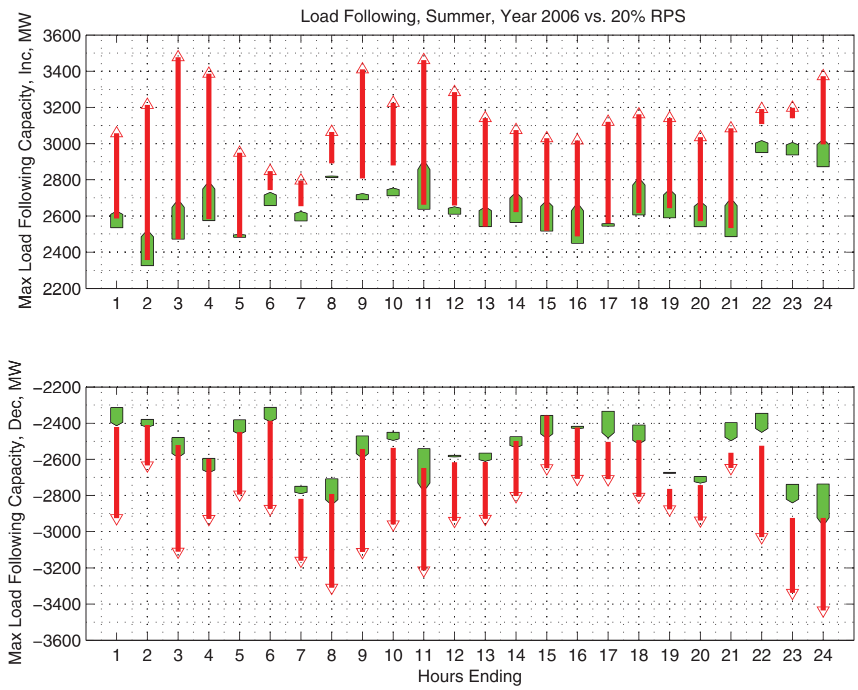


Figure 5-16: Load Following Capacity Requirement

5.8.4. Load following ramping requirement

Figure 5-17 shows the hourly load following ramping requirements due to wind to meet the 20% RPS (red arrow) compared to wind only for 2006 (green arrow). It is expected that the maximum upward load following ramping requirements will increase by 40 MW/min. (HE23: 210-170). Similarly, the maximum downward load following ramping requirements will increase by 40 MW/min (HE9:180-140).

5.8.5. Existing ramping capability

There is currently about 12,651 MW of capacity certified for Ancillary Services (AS) within the California ISO. The ramp rates of these resources range between 2.25 MW/min. to 187.7 MW/min. Only 7,521 MW of this capacity have ramp rates of 10 MW/min. or greater. Hydro units account for 4,700 MW of the AS capacity with ramp rates of 10 MW/min. or greater, while thermal resources account for the remaining 2,821 MW.

Currently, there is about 7,141 MW of capacity certified to provide regulation with ramp rates greater than 10 MW/min. Hydro facilities account for 4,700 MW of this capacity; however, only five of these hydro facilities (2,788 MW) have ramp rates greater than 100 MW/min. The remaining 2,441 MW of regulation capacity are from thermal capacity, which has ramp rates between 10 and 31 MW/min.

Based on the regulation requirements shown in Table 5-5, the current generation mix seems adequate to meet the anticipated regulation needs. However, during droughts or low hydro years, regulation response could be slow due to the reliance on thermal units with slower ramp rates. Depending on system load, additional units may have to be committed on-line to meet regulation needs, especially during the summer months. With the current advancements in storage technology, faster ramping devices such as flywheels may be an alternative to committing additional resources to meet regulation requirements in drought years.

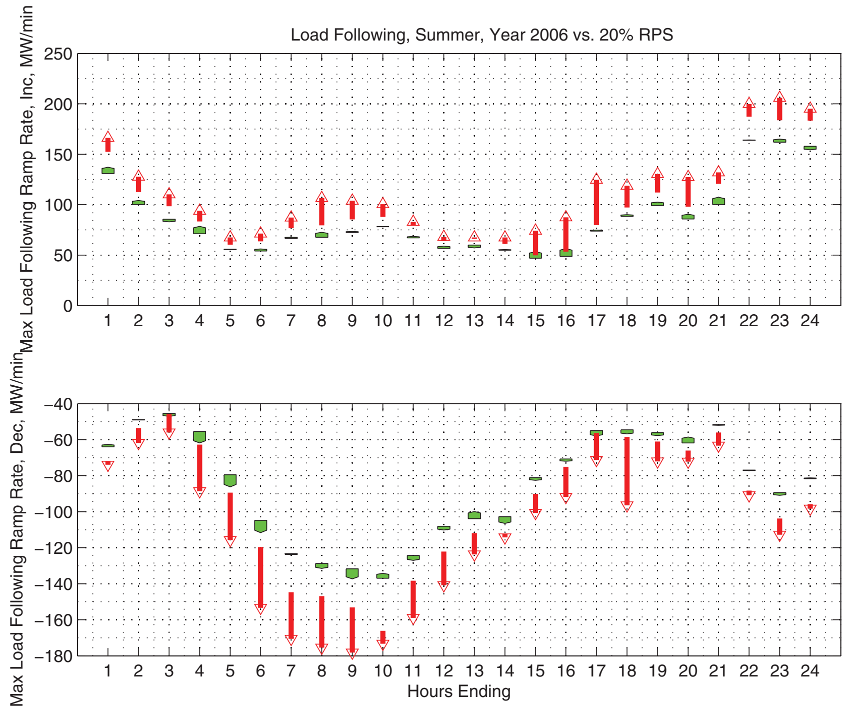


Figure 5-17: Load Following Ramping Requirement

5.8.6. Load following ramp duration

As shown in Figure 5-18, the upward ramp duration is required for approximately 30 minutes, while the downward ramp duration will be required for approximately 20 minutes. Overall, the upward load following capacity needs to be about 3,500 MW, and resources within the supplemental stack should be able to ramp up at a rate of about 80 MW/min. for approximately 30 minutes. Similarly, in the downward direction, the resources should be able to ramp down at a rate of approximately 175 MW/min. for at least 20 minutes. Refer to Appendix A for graphs showing the capacity, ramps and ramp duration for all seasons.

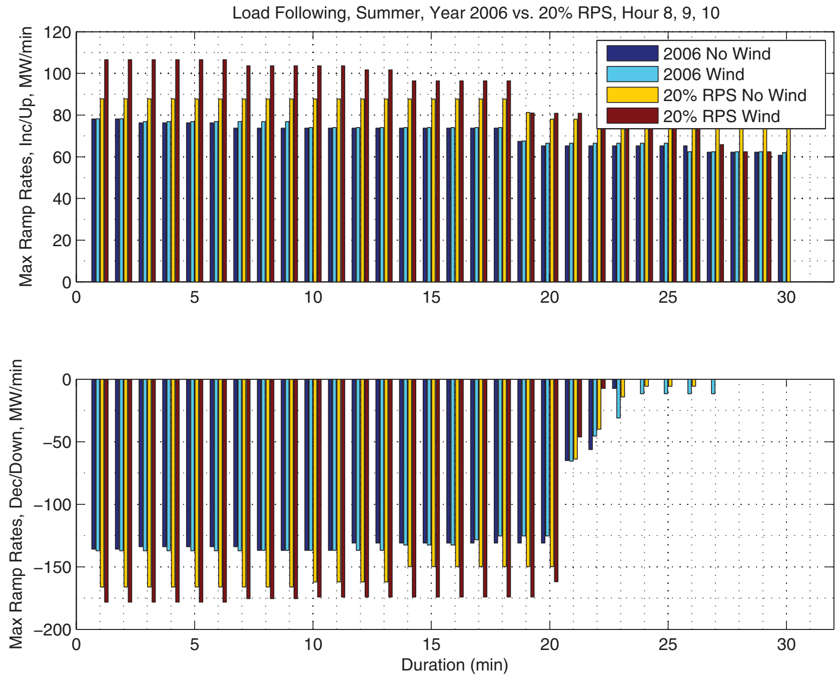


Figure 5-18: Load Following Ramp Duration

5.8.7. Study result summary

As shown in Table 5-2, the California ISO will require a significant increase in the supplemental energy stack to meet intra-hour load following needs. The increase is explained by the fact that the Hour-Ahead wind generation forecast error (with a standard deviation of 7% to 9% of the total installed wind generation capacity) becomes comparable with the Hour-Ahead load forecast error (with a standard deviation of 600 MW to 900 MW).

Table 5-2: Summary of Load Following Capacity

Season	***Max Load Following (Inc) MW***	***Max Load Following (Dec) MW***	***Max Hourly Increase (Inc) MW***	***Max Hourly Increase (Dec) MW***
Spring	2,850	-3,000	+800	-500
Summer	3,470	-3,430	+800	-600
Fall	3,080	-3,200	+750	-900
Winter	2,850	-3,050	+700	-750

The California ISO maximum load following ramping requirements to meet the 20% RPS is expected to increase by about ±30 to ±40 MW/min. These increases will affect ADS ramps up to 20-30 minutes long.

Table 5-3: Summary of Load Following Ramps

Season	Max Load Following Ramp Up MW/min	Max Load Following Ramp Down MW/min
Spring	+35	-30
Summer	+40	-40
Fall	+40	-30
Winter	+30	-40

5.9. Sensitivity with 5% Wind Forecast Error

Holding all other assumptions constant, a sensitivity with the Hour-Ahead wind generation forecast error with a standard deviation of 5% of the total installed wind generation capacity was evaluated. A summary of the load following sensitivity is set forth in Table 5-4 below.

Table 5-4: Summary of Load Following Capacity (5% Error)

Season	INC 7%-9%	INC 5%	Reduction MW	Reduction %	DEC 7%-9%	DEC 5%	Reduction MW	Reduction %
Spring	2,850	2,450	400	14.0%	-3,000	-2,550	-450	-15.0%
Summer	3,470	3,320	150	4.3%	-3,430	-3,280	-150	-4.4%
Fall	3,080	2,550	530	17.2%	-3,200	-2,600	-600	-18.8%
Winter	2,850	2,660	190	6.7%	-3,050	-2,700	-350	-11.5%

5.10. Regulating Requirements

The California ISO maintains sufficient generating capacity under automatic generation control (AGC[27]) to continuously balance its generation and interchange schedules to its Real-Time Load. This generating capacity under AGC is referred to as regulating reserve.[28] The WECC does not specify a regulating margin based on load levels but requires adherence to the NERC's Control Performance Criteria.

The California ISO does not dispatch regulating reserve based on its energy bid curve price, but automatically dispatches regulation through AGC every four seconds to meet moment-to-moment fluctuations in customer load demand and to correct for the unintended fluctuations in generation. Regulation is wholly based on the resource's effectiveness to maintain system-scheduled frequency and to maintain scheduled flows between balancing authorities while taking into consideration the resource's operating constraints. To the extent that a resource is moved away from its Dispatch Operating Point (DOP) by AGC (i.e., it is not awarded imbalance energy); the market clearing software assumes that the resource is brought back to its DOP in the next market interval. In doing so, the net energy delivery from the unit, both above and below its DOP, averaged over time, to zero.

To meet the NERC's Control Performance Criteria, the California ISO typically procures ± 350 MW of regulating reserve (approximately 1 to 1.5% of load) on a given day. On days with high load demand, additional regulation is procured. Although the regulation dispatch is conducted every four seconds, the regulation margin has to be adequate to meet deviations within a 5-minute dispatch interval.

27 The WECC defines AGC as equipment that automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

28 The WECC defines regulating reserve as sufficient spinning reserve, immediately responsive to automatic generation control (AGC), to provide sufficient regulating margin to allow the control area to meet NERC's Control Performance Criteria.

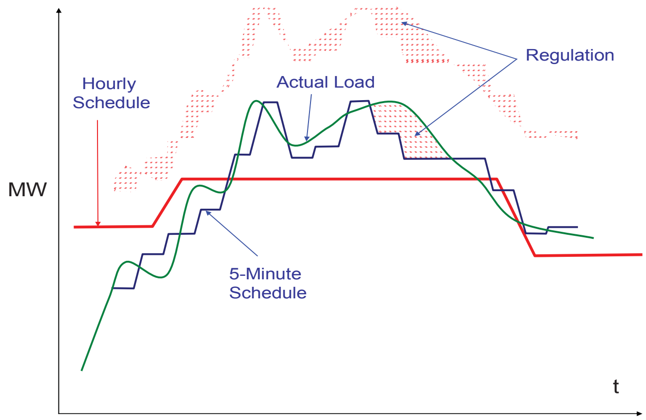


Figure 5-19: Regulation Requirement Shown as the Red Shaded Area

As stated in section 5.8.1, ADS instructions are issued approximately 7.5 minutes in advance of the desired operating interval leaving approximately 5 minutes for units to move to their desired operating point. As shown in Figure 5-19, during this 5-minute time frame, deviation from generation schedules is compensated with regulation, which is dispatched through Automatic Generation Control (AGC) within the California ISO's Energy Management System (EMS). Regulation is not dispatched by the California ISO's Real-Time Market System.

5.10.1. Regulation capacity requirements

With increased wind generation the California ISO regulation capacity requirements would increase noticeably during certain hour ranges. The increase is explained by increasing inaccuracy of the persistence model used in this study for the Real-Time wind generation forecast (this model reflects the current approach implicitly used by the California ISO's Real-Time Dispatch). Appendix B outlines the study methodology used to evaluate the regulation requirements due to wind generation.

As shown in Figure 5-20, the maximum upward regulation capacity requirement of 480 MW occurs during HE9, while the maximum downward capacity requirement of -750 MW occurs during HE18. The hourly upward increase is simply the difference between the top of the red arrow and the top of the green arrow for each hour. The hourly upward increase is simply the difference between the top of the red arrow and the top of the green arrow for each hour. The maximum increase of 230 MW occurs during HE9 (480 MW-250 MW). The maximum downward increase of 500 MW (750 MW-250 MW) occurred in HE18.

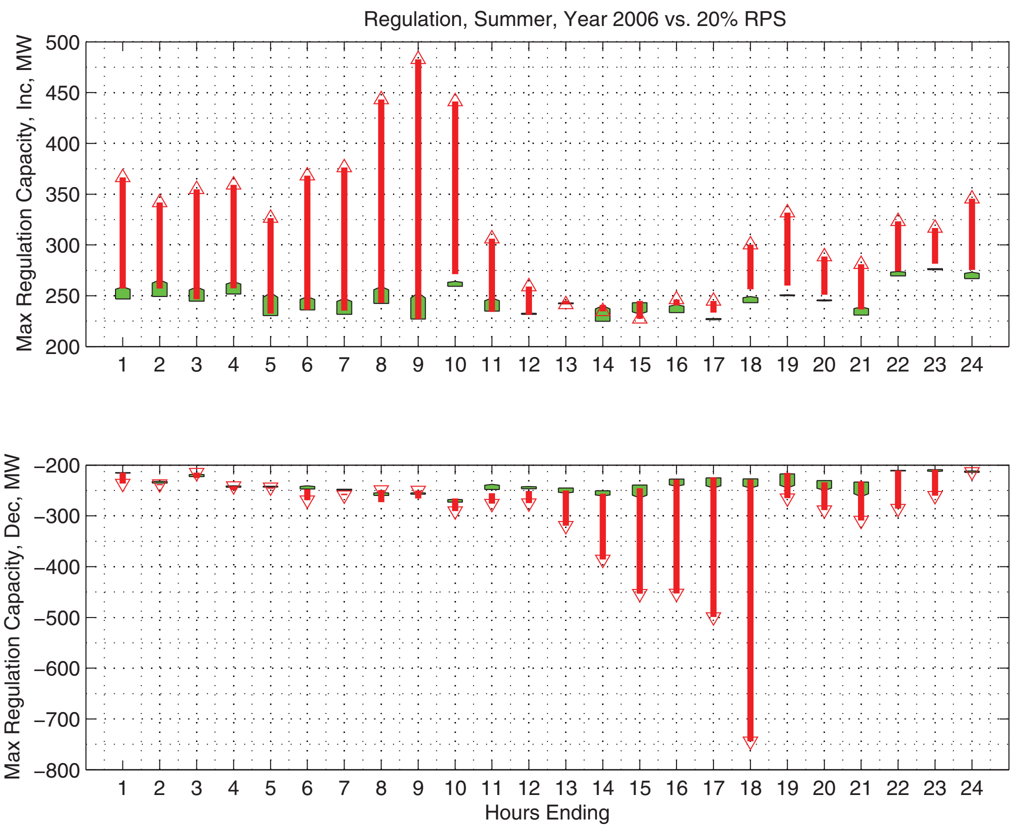


Figure 5-20: Maximum Regulation Capacity

5.10.2. Regulation ramping requirements

Figure 5-21 shows the hourly regulation ramping requirements due to the addition of only wind. It is expected that the maximum upward regulation ramping requirements to meet the 20% RPS will increase by 10 MW/min (HE10: 140 MW/min-130 MW/min). The maximum downward regulation requirement is expected to increase by 18 MW/min (HE10:115 MW/min - 97 MW/min). This is not expected to create any operational concerns because it falls within the ramping capability of the existing units. The regulation ramp duration is expected to increase by about ±10 to ±25 MW/min. and could last for about 5 minutes. For further information see Appendix A.

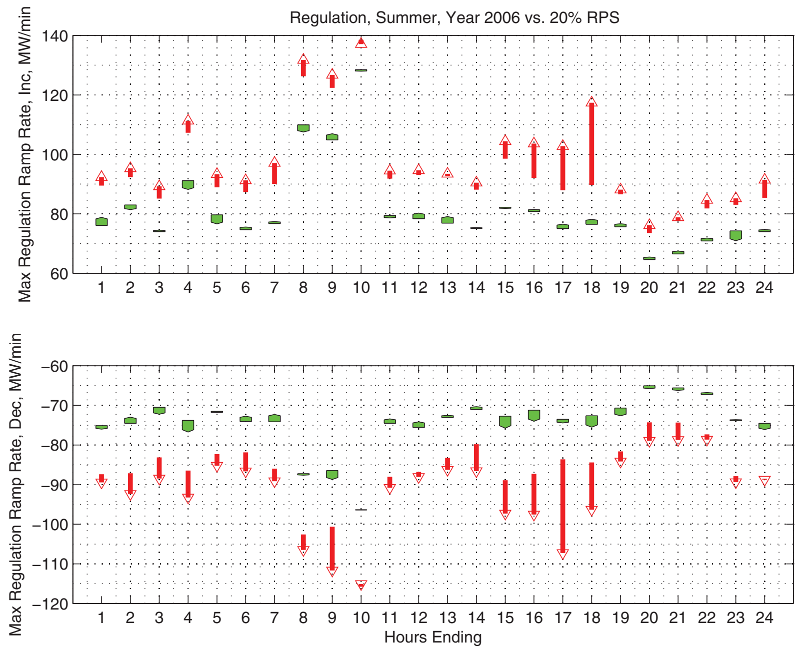


Figure 5-21: Regulation Ramp Rate

5.10.3. Regulation ramping duration

As shown in Figure 5-22, both the upward and downward ramp durations are required for about 5 minutes. Overall, the upward regulating capacity needs to be about 480 MW, and resources within the supplemental stack should be able to ramp up at a rate of about 80 MW/min. for at least 5 minutes. Similarly, in the downward direction, the regulating capacity needs to be about -750 MW, and resources should be able to ramp down at a rate of approximately 80 MW/min. for at least 5 minutes. Refer to Appendix A for plots showing the load following and regulation capacity, ramps and ramp duration for all seasons.

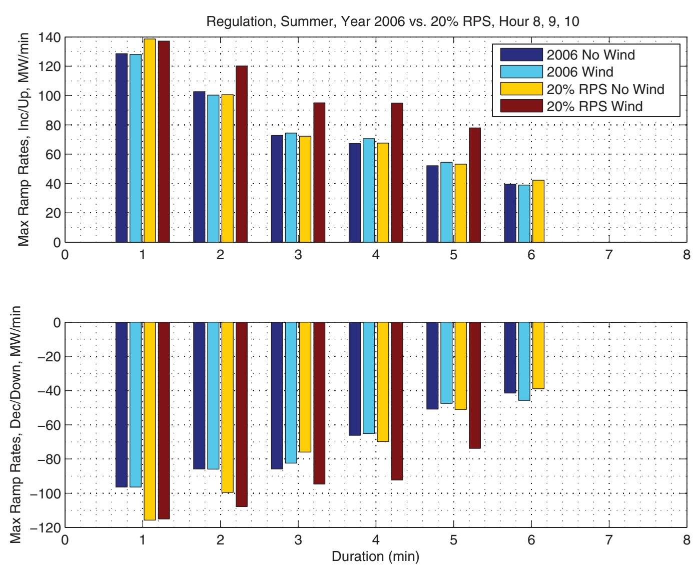


Figure 5-22: Regulation Ramp Duration

5.10.4. Regulation study result summary

The California ISO regulation capacity requirements would increase noticeably during certain hours. The increase is explained by increasing inaccuracy of the persistence model used in this study for the Real-Time wind generation forecast. Table 5-5 summarizes the maximum expected values.

Table 5-5: Summary of Regulation Capacity

Season	Max Regulation Up MW	Max Regulation Down MW	Max Hourly Increase (Up) MW	Max Hourly Increase (Down) MW
Spring	+510	-550	+240 (HE18)	-300 (HE18)
Summer	+480	-750	+230 (HE09)	-500 (HE18)
Fall	+400	-525	+170 (HE06, HE18)	-275 (HE18)
Winter	+475	-370	+250 (HE18)	-100 (HE10)

To meet the 20% RPS, the California ISO regulation ramping requirements will increase by about ±20 to 35 MW/min. (see Table 5-6). These increases will affect AGC ramps up to 5 minutes long.

Table 5-6: Summary of Regulation Ramps

Seasons	Max Regulation Ramp Up MW/min	Max Regulation Ramp Down MW/min
Spring	+20	-25
Summer	+10	-18
Fall	+25	-20
Winter	+15	-15

5.11. Over-Generation Conditions

One of the concerns of grid operators about wind generation is that its energy can show up unexpectedly causing an imbalance between load and generation. Whenever there is an imbalance between generation and load, the California ISO's Automatic Generation Control (AGC) system sends control signals to units on regulation to move to different operating points in order to correct the imbalance. During over-generation conditions, regulating units are moved to the bottom of their regulating range and the Real-Time Economic Dispatch System drives units with decremental (DEC) bids to their minimum operating points. At times, operators may run out of DEC bids and have to go out of market to drive the units down further or command units to shut down.

Over-generation occurs whenever there is still more generation than load and the operators cannot move generators to lower the level of production. The controllable generation and imports are at their minimum levels or are shut down, exports are maximized and the total net generation production still exceeds the system load. The Real-Time energy prices typically go negative and the California ISO, at times, literally pays adjacent balancing authorities to take the excess energy.

This condition is most likely to occur if the following circumstances are present:

- Light spring load conditions with loads around 22,000 MW or less
- All the nuclear plants on-line and at maximum production
- Hydro generation at high production levels due to rapid snow melt in the mountains
- Long start thermal units on-line and operating at their minimum levels because they are required for future operating hours
- Other generation in a regulatory "Must Take" status or required for local reliability reasons
- Wind generation at high production levels

Figure 5-23 below helps to illustrate the over-generation problem:

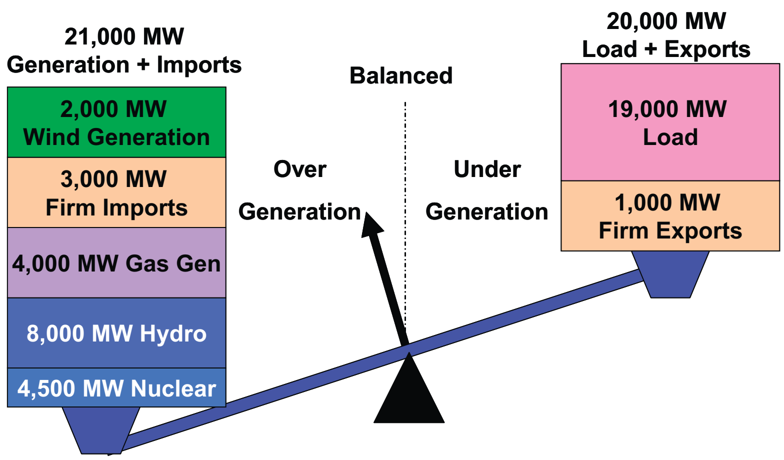


Figure 5-23: Over-Generation

In addition, the problem is exacerbated by, the lack of an accurate Day-Ahead forecast of wind generation energy production and the lack of a system to check and verify the feasibility of next day schedules. Even if some portion of the wind generation energy is scheduled in the Hour-Ahead market, it may be too late to correct the mismatches between load and generation schedules. The SCs help by attempting to sell the excess energy to other entities within the interconnection. The over-generation problem finally gets resolved, but the operators may incur several NERC Control Performance Standard violations in the process.

The CEC 2007 IAP Final Report identified over-generation as a potential problem during light load conditions. The minimum operating points for many of the generators in the California ISO market database do not always match the operator's experience with the unit's actual minimum operating levels due to environmental, economic and operating constraints of the plants.

5.11.1. 2006-2007 Over-generation analysis

In 2006, there were 45 hours of over-generation problems on 20 different days, and in 2007, there were six reports from January through May 2007. All of the incidents identified a problem with a mismatch or generation schedules with forecast loads. Although wind production levels played a very small role in over-generation problems in 2006 and 2007, it is anticipated that high levels of wind generation after the 20% RPS build out could cause operational challenges during light load conditions.

Example of a typical log entry for over-generation:

"05/06/2007 - 0615 Real -Time Over-Generation"

"**Description:** "Real-time over-generation condition for HE 0700"

> ***Details:*** "For hour(s) ending 07, the California ISO has determined over-generation in the amount(s) of 500 MW. The California ISO may be invoking other steps in its over-generation procedure G-202, including, but not limited to, purchasing Out-Of-Market (OOM) decremental energy for this hour. Scheduling Coordinators should contact the California ISO Generation Dispatcher if they desire to provide OOM decremental energy for this period. To the extent that Scheduling Coordinators do not respond to this California ISO notice of over-generation, the California ISO may invoke other steps in the over-generation procedure G-202, including but not limited to pro-rata reductions and mandatory generation reductions."

An example of over-generation with a clear correlation to wind generation energy production occurred in April 2006 for HE13 through HE19. At around 1130 hours, the wind generation ramped up from 600 MW to more than 1,000 MW in approximately one hour. The operator declared a 500 MW over-generation condition and the ACE remained high during this period. This event occurred on a light load day as the system load was in the 23,000 ±500MW range at the time.

Figure 5-24 shows the wind generation production for that day and the corresponding ACE. Figure 5-25 shows the Real-Time prices for the same day, which were negative for a significant portion of the over-generation period.

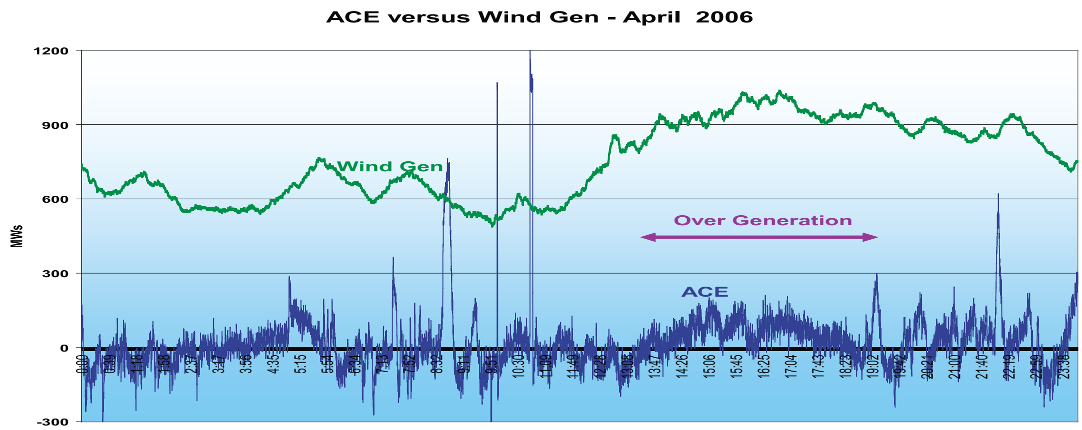


Figure 5-24: ACE versus Wind Generation

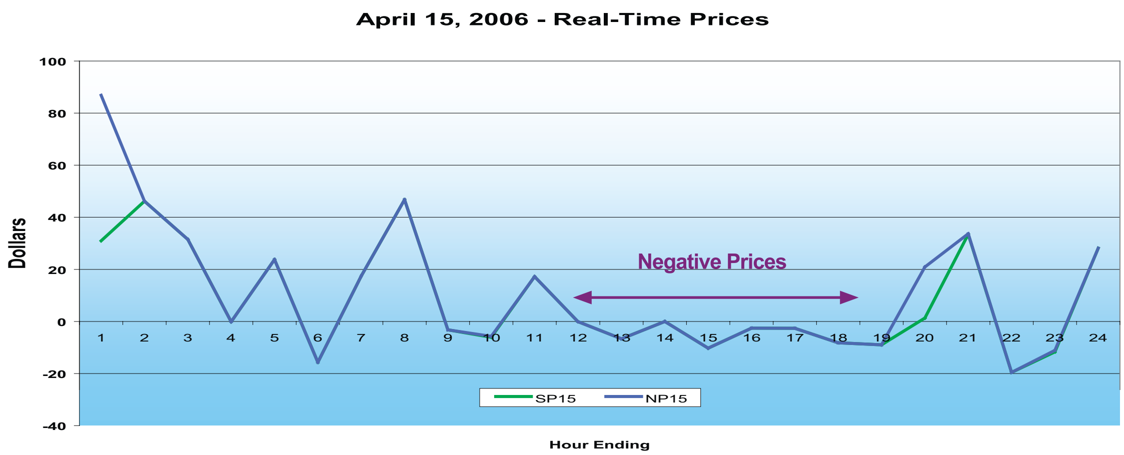


Figure 5-25: Real-Time Prices During Over-Generation Conditions

During the 2006 spring months (March, April & May), there were 208 hours when the California ISO load was less than 20,000 MW. The minimum amount of load (minus wind generation) recorded in 2006 was 18,070 MW. Table 5-7, shows a summary of the minimum generation that was on-line during light conditions.

Table 5-7: Minimum Generation Levels by Technology During Light Load

Generation/Load	Production Level Spring 2006 (MW)
Nuclear	4,528
Minimum "Must Take" such as QFs	2,400
Minimum Geysers	650
Minimum Thermal	1,000
Minimum Hydro	3,700
Minimum Interchange	2,880
Total Generation plus Interchange	***15,158***
Minimum Load	18,070
Difference	***2,912***

Based on the minimum generation levels shown in Table 5-7, assuming conditions remain the same with the build out, the maximum amount of wind generation that could be accommodated would be about 2,912 MW.

The critical components for over-generation appear to be maximum hydro generation, maximum wind generation, low system load, all nuclear plants on-line, heavy imports on the ties and other generation required to be on-line due to operating constraints. Under these conditions, over-generation is likely. Light loads and high wind generation is not a good gauge for over-generation. It is therefore difficult to predict the number of hours wind generation would have to be curtailed in 2010, during light load conditions, without accurate Day-Ahead wind forecast. This problem is exacerbated during favorable hydro conditions or when SCs have already made commitments in the forward markets to purchase inexpensive imports.

The fact that the California ISO had 45 hours of over-generation in 2006 with the current level of wind generation on the system leads to the conclusion that over-generation problems can be expected in the future when there is 3,000+ MW of wind generation. Whether wind is the cause or other factors are the cause, the California ISO will need to take action to reduce the amount of generation on the system when this occurs. This will include sending dispatch notices to wind generation facilities for their operators to take action to reduce their generation at the wind facilities. The California ISO recognizes the state's resource loading order, which places renewable resources low on the list for pro-rata cuts, but the California ISO may occasionally have to implement such cuts to ensure the reliability of the system.

5.11.2. Over-Generation in the MRTU environment

Under the new MRTU Integrated Forward Market (IFM), over-generation is managed as part of the IFM Unit Commitment process. The IFM ensures that the scheduled supply for each trading hour equals the quantity of scheduled demand. Wind generation energy does not have to be scheduled in the Day-Ahead market, but the SCs may elect to schedule some of the energy. After the Day-Ahead Market closes, the California ISO runs the Residual Unit Commitment (RUC) process to ensure sufficient generation will be on-line the next day to meet reliability requirements. If more energy supply is scheduled than the California ISO forecast demand for the next day, then the RUC process may identify the need to de-commit resources. One key input before the RUC process is initiated will be a Day-Ahead forecast for wind energy production. The RUC process should not identify the need for additional generation if there is a good chance that the generation will not be needed due to forecast wind generation energy production.

The RUC does not automatically de-commit a resource scheduled in the IFM. The California ISO operator may communicate the need for de-commitment of resources with affected market participants. If the Day-Ahead wind generation forecast is reasonably accurate, the potential over-generation problems can be resolved and feasible energy production schedules created for the next operating day.

In the actual operating day, the California ISO runs the Hour-Ahead Scheduling Process (HASP) that is used to lock in changes to schedules 75 minutes before the actual operating hour starts. The schedules for the wind generators in the PIRP program will be locked in at the 75 minute point. HASP provides the California ISO the opportunity to deal with over-generation by economically clearing an export bid in HASP in order to avoid manual intervention to decrease generation in Real-Time. If the over-generation condition continues in Real-Time, the Real-Time Market (RTM) attempts to dispatch resources down using economic bids to the extent possible to relieve the over-generation condition. If use of economic bids is insufficient, then supply curtailment is performed in accordance with Section 34.10.2 of the California ISO tariff.

Lastly, exceptional dispatches may be necessary to resolve the over-generation condition. The RUC solution identifies to the California ISO operator the resources that may need to be considered for de-commitment. The California ISO operator reviews and assesses the results prior to making any manual de-commitment decisions. The RTM applications use the latest information on hand about resource availability and network status; in fact, the optimal dispatch is initialized at the SE solution that is provided by the Energy Management System (EMS).

5.11.3. Conclusions and recommendations about over-generation

- Over-generation does occur with the existing amount of wind generation, but it is a relatively rare occurrence.

- The lack of good Day-Ahead wind generation forecasts contributes to the problem. Without good forecasts, other generation resources and imports on the ties may be over scheduled. This mismatch of energy production schedules with forecast loads is a key part of the problem.

- The addition of large amounts of wind generation facilities to meet the 20% RPS will exacerbate the problem. The fact that this problem is already visible with the amount of installed wind generation today means that this will become a much more serious problem as the amount of wind generation doubles and triples in the near future.

- The MRTU Integrated Forward Market should help mitigate the problem once it goes live in 2008 as it will ensure the generation schedules match the load forecast. Accurate Day-Ahead wind generation forecasts will be a key component for the Day-Ahead RUC process.

- As pointed out in the CEC IAP report, the wind generation operators should be prepared to curtail some wind generation production for up to 100 hours per year to mitigate serious over-generation conditions in the future. The amount of renewable energy that will be lost is expected to be small. The hourly pro-rata cuts will probably be less than 500 MW. Curtailment of some wind generation energy production for a few hours per year may be the practical solution to address over-generation.

- The California ISO must work with the wind generator operators to ensure procedures, protocols and communication facilities are in place so dispatch commands can be communicated to the wind plant operators.

- Additional storage capability on the system would help to mitigate both over-generation and large ramp conditions. For example, upgrading the transmission system to the Fresno area would allow frequent use of the third pump at the Helms Pump Storage plant. The third pump adds 300 MW of additional load to the system, which could help to absorb the increased wind generation at night and during light load periods.

- There must be continuing exploration of other storage technologies and off-peak loads that can be combined with the wind generation production. The plug-in hybrid vehicle projects underway at both SCE and PG&E as plug-in hybrids could ultimately add significant night time load to the system.

Chapter 6 – PIRP II Enhancements

In 2003, the California ISO created the Participating Intermittent Resource Program (PIRP) to lower a perceived barrier to wind generation participation in the California ISO markets and Real-Time operations. PIRP allows intermittent resources to schedule energy in the Hour-Ahead Market without incurring imbalance charges when the delivered energy differs from the scheduled amount. Participating Intermittent Resources that schedule in accordance with the Hour-Ahead forecast provided by the forecast vendor will not receive imbalance energy charges for deviations across a 10-minute settlement interval. Instead the megawatt deviations from a Participating Intermittent Resource will be netted across a calendar month and settled at a weighted-average price. With an unbiased, state-of-the-art forecast, the expected net deviation should be somewhat low.

The success of the PIRP is dependent on the accuracy of the forecast provided to the wind plant SC by a Forecast Service Provider (FSP) 2 hours and 45 minutes before the operating hour (the Hour-Ahead [HA] forecast). The HA forecast requires Real-Time data from each wind plant site, and the forecast accuracy is dependent on the quality of data from that plant. Unfortunately, the original implementation of the PIRP application did not anticipate the California ISO's need to check the data[29] quality from each of the wind plants and the need for the California ISO to report data problems to the wind plant operators. The need for an errant data feedback system became more obvious as more wind plants were brought on-line and into the program. An informal manual e-mail system was established to fill the feedback gap with the FSP doing the data quality checks. Although this improved the data quality, it included serious delays in the reporting of bad data as the data checking was too far downstream in the process. Delays of several days or longer were not uncommon to identify and correct communication problems, missing data and bad data from devices at the various wind plant.

In 2006, the California ISO started work on major upgrades to the PIRP to fix this problem and add other system features. The PIRP II project included major enhancements to the PIRP application software to detect bad data and to automatically report problems in a timely manner to the wind plant operators. The primary objective was to provide the wind plants SCs with timely information regarding their participation in PIRP without manual intervention. Information provided to the wind plants SCs give immediate errant data feedback when the wind plant retrieves their HA forecast, thus eliminating the need for a manual feedback system. With the added visibility to errant data that PIRP II provides, the California ISO is now performing a study to determine the following: the different types of errant data; the cause of the errant data, the responsiveness of the PIRs to the notifications of errant data; and what corrective action can be taken to improve the forecast accuracy in the future.

29 Errant data is when the PIRP application has determined that for one or more reasons, the Resource's Met/Gen data is either unavailable or is not passing one of the many data quality validations.

The PIRP II also addressed issues such as future scalability; added an internal PIRP administrator console for ease of managing users, resources and application configuration settings; improved audit capability of data the FSP provided to the California ISO; and provided safeguards for the speedy recovery of the PIRP database should a loss of data occur.

The new PIRP II system went into operation at the California ISO in May 2007.

Chapter 7 - Storage Technology

Battery storage and pump hydro storage systems have been around for many years, so the concept of energy storage is not new. Large pump storage facilities have been proven to be very effective in shifting large quantities of low cost off-peak energy production to delivery during high cost on-peak energy periods. However, large pump hydro storage facilities are quite costly, and there are very few locations where they can be built. Battery storage systems are also relatively costly and have limited amounts of energy storage.

New types of energy storage technologies are needed that can help with the integration of large amounts of renewables and energy from intermittent resources. R&D efforts have accelerated over the past several years to develop and test new storage systems. Several types of systems are being evaluated as potential new storage technology, and in this chapter, the following are discussed: Hydrogen, compressed air, closed loop pump hydro storage, flywheel systems, super capacitors and flow batteries.

A number of problems with new storage technology must be overcome in order for the technology to be competitive. These problems include the following:

- The capital costs are quite high for new storage facilities – typically $1 million to $1.5 million per MW of capacity.

- The efficiency of new systems is still low. Efficiency numbers are not typically available, but they appear to be less than 75% for many of the technologies. This means that 25% or more of the energy supplied to these system is not recovered. Some technologies have losses due to pump operation, some have compressor loads and others have inverter losses. The efficiency of the high speed flywheels is better than most of the new technologies as they are in the 80% to 90% range. Their losses are due to the power electronics of the inverters and not due to losses in the flywheel itself.

- Storage systems are a net negative system device. They look more like a load than a generator. Their preferred operating point will be zero or slightly negative as they consume power from the grid to perform their storage function. When they are absorbing power from the grid, they are essentially buying power at the Real-Time energy price. When they are supplying power, they would be selling power at the Real-Time energy price. One question will be whether there should be a special tariff for storage systems.

- The amount of energy storage capability of these systems is typically quite limited. Batteries and high speed flywheels can deliver their rated output for 10 to 15 minutes. Flow batteries, hydrogen storage and compressed air systems can probably deliver energy for an hour or two, but so far have not demonstrated they could delivery energy for ten hours or longer. The sodium-sulfur (NAS) battery developed in Japan, delivers 7 to 8 hours of stored energy at installations currently up to 12 MW of capacity.

- There are not good economic models or operating data on the various technologies to prove they make a good business case.

- To encourage commercial investment in new storage technologies, the first deployments may need investment tax credits similar to those enjoyed by the wind generators for the past several years.

- The first commercial deployments of new storage technology will probably need some type of a grid services performance contract to share the financial risk. This will help the owner/operator obtain financial backing for the new venture and provide a chance to validate the business economics of the system. Part of the services they provide could still be market based and part could be contract performance based, similar to RMR contracts.

- The DOE and the CEC investments in storage technology R&D projects are critical for the development of these new technologies. The results of the R&D projects should be published to provide the data required for commercialization.

- The California ISO needs to continue to develop new methodologies for dispatching different types of storage systems. The traditional AGC signal sent to hydro generation for regulation services is probably not going to work for storage systems like flywheels that need lots of charge and discharge cycles per hour. The response of high energy capacity NAS battery systems to AGC signals is yet to be demonstrated.

- Based on the industry feedback to the California ISO on the LEAPS project, it is clear that the California ISO should not be the owner/operator of large hydro pump storage facilities. This may also be true for other types of storage technology. Should all storage facilities be independently owned and their services market based or should some of them be owned and operated by the transmission operators?

- Storage facilities can provide a number of benefits that will help with the integration of large amounts of renewable resources. Storage provides a mechanism for saving off peak energy production from wind generation and delivering the energy during on-peak periods. Some storage technologies can also provide ancillary services such as regulation and contingency reserves and reactive power for voltage support. The major barrier for construction of new storage facilities is not the technology but the absence of market mechanisms that recognize the value of the storage facilities and financially compensate them for the services and benefits they can provide. The California ISO will participate with the IOUs, stakeholders and potential providers of storage technology to design market products that properly compensate storage facilities for the benefits they can provide.[30]

30 Response to comment from Ed Cazalet, Megawatt Storage Farms, Inc.

7.1. Benefits of Storage Technology

7.1.1. Mitigates over-generation problems

Dispatchable loads and energy storage systems can add significant flexibility to the operation of the power grid. They can often respond in a few seconds to commands to absorb energy. Each type of technology has its unique response rate, some in one second and others within a few minutes, but all can quickly connect to the system and ramp up to add load to the system. For example, large pump storage plants can be switched from generation mode to pumping mode within approximately 15 minutes. The addition of up to 500 MW of new storage capability to the system, with the ability to respond to the California ISO dispatch commands, would add major flexibility for the operators to deal with over-generation problems. Load could be added to the system either by the storage owner/operator as a market participant or by dispatch notice from the California ISO to rebalance the system.

A second issue is the need to increase the amount of off-peak load on the system that could take advantage of the off-peak energy production from wind generation. An example would be the dispatch of major state pumping load to increase or decrease system load as the wind generation production increases and decreases. Another example is the potential growth in load from plug-in hybrid vehicles. If feasible these changes could provide system load that is matched with the off-peak energy production from renewables.

7.1.2. Mitigates large ramps

Storage systems can quickly supply energy to the system when needed and help with the mitigation of large load and/or wind generation energy ramps. The CEC IAP report identified the fact that the California ISO will have to deal with energy ramps of several thousand megawatts per hour during some periods. Short-term ramps that often occur at the top of the hour can be another challenge. Storage systems that can quickly inject power into the system or add a block of load could mitigate some of the ramp problems and allow other resources to be dispatched and catch-up with the ramp. Flywheel systems, for example, can ramp up to full output in approximately one second and hold that level of production for 10 to 15 minutes. Hydro units and pump storage units all have fast ramp rates and can usually sustain the maximum level of production for several hours or longer. A portfolio of fast responding units like hydro and storage facilities in combination with other units that can move through large ranges of output will enhance the integration of large amounts of renewable resources.

Storage technology has the advantage of not using fossil fuel, so storage facilities do not directly contribute to greenhouse gas production. If the energy in storage comes from renewable resources, they are simply storing the green energy and delivering it back to the system when it is needed. If load is ramping up as wind is ramping down, storage can provide the added energy to mitigate the resulting net energy ramp.

7.1.3. Provides Ancillary Services

As discussed earlier in this report, an increase in the amount of wind generation will require increases in the amount of regulation and load following capability. Flywheel and NAS battery systems are ideally suited to provide some of the added regulation. Both technologies can provide up to 40 MW of regulation services and eliminate the need to move fossil fuel units up and down a few megawatts at a time. Hydro, pump storage and fossil fuel units will still be needed for large ACE deviations and macro AGC control.

Hydro generation and pump storage are excellent sources for the required system operating reserves as they can provide this capacity without the use of fossil fuel. They can be synchronized to the system and be ready to produce substantial energy on demand. A pump storage plant like Helms Pump Storage Facility can provide 600 MW or more of operating reserves and rapidly ramp up its output if required due to the loss of a large unit on the system.

7.1.4. Provides reactive energy for voltage support and, could reduce the need for RMR units

Storage technology typically uses some other medium to store the electrical energy. This can be a rotating mass, water, chemical, compressed air, hydrogen or something other than storage of electrons. Most of these systems require some type of generator and an inverter to create 60 Hz synchronized power that is delivered back to the grid. If the systems have an inverter, this device can deliver reactive power as well as real power, which means the systems can help to support the voltage in that area. It is also possible to locate these devices in a warehouse or near a load center, which means they can provide reactive power to support the voltage in a transmission constrained area. Storage technology devices could compete with Reliability Must Run (RMR) generators to provide reactive power, dynamic VARs and voltage support.

7.1.5. Shift energy from off-peak to on-peak delivery

One value of large storage systems is the ability to absorb energy during off-peak periods and then deliver the energy to the system at peak periods. If the wholesale price differential between off-peak and on-peak periods is large, then the storage technology can be economically justified.

All storage systems are net-negative devices, which mean there is some loss of energy in the systems. If the device has a “round-trip” efficiency of 75%, then for every 100 MWh of energy input into the storage device, only 75 MWh of energy is recovered and returned to the grid. Therefore, the price differential between off-peak and on-peak energy would need to be 1.33 to 1 or greater to make a profit with the storage system for shifting of energy. If the on-peak/off-peak price differential is small, then the owner/operators of storage technology need to sell additional services such as regulation or operating reserve capacity to supplement the profit stream for the technology.

7.2. Pump Storage and the Need for Three Pump Operation at Helms

Pump storage is a proven storage technology. It has been around for many years, and California is fortunate to have a number of pump storage facilities. One of the largest facilities is the Helms Pump Storage Facility that was built in the early 1980s with three units. Each unit is rated at 400 MW in generation mode and 310 MW in pumping mode for a total of 1,200 MW generating mode and approximately -900 MW pumping mode. The pump motors are non-variable speed motors, so the load operation is rather stepwise as shown in Figure 7-1 as the units come on and off in 300 MW steps. When a pump is tripped, it actually moves the frequency of the Western Interconnection enough to trigger the system frequency alarm.

A sort of the hourly energy data shows the amount of time for the various pumping modes at the plant.

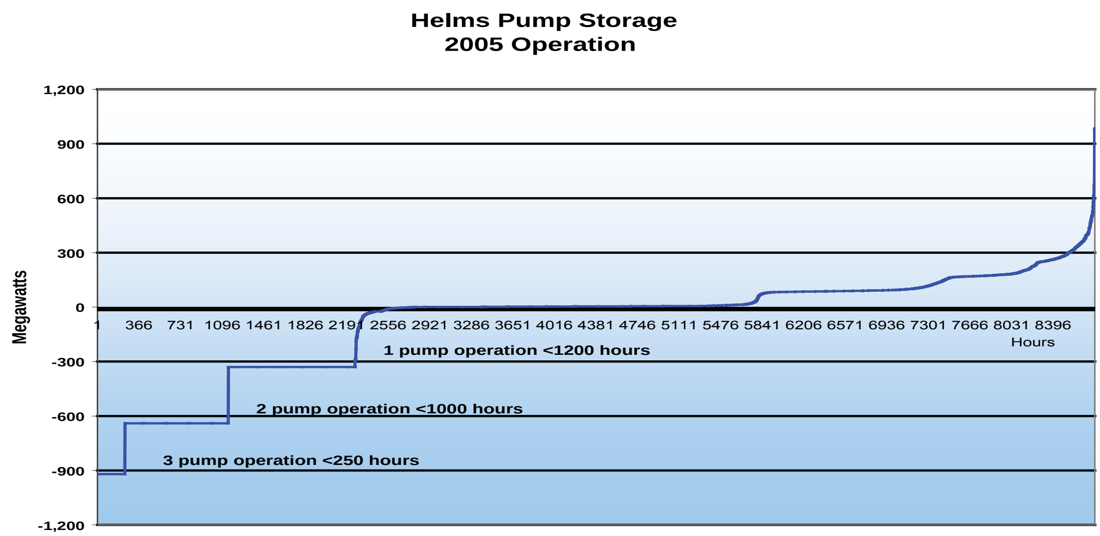


Figure 7-1: Helms Pump Storage Operation in 2005

The simultaneous operation of all three pumps at Helms is currently limited by transmission constraints in the Fresno area. The fact that three pumps are on less than 3% of the total time per year will become a more serious problem as the amount of wind generation on the system increases. An additional 300 MW load at Helms due to three pump operation instead of only one or two pumps during off-peak periods would add a valuable sink for the excess off-peak wind generation. PG&E has proposed a transmission upgrade plan for the Fresno/Helms area that would enable three pump operations for many additional hours per year. The new plan will also move the energy from the wind farms in Tehachapi to the Helms facility. Both the GE studies and the California ISO studies have shown that operation of three pumps at Helms will help to mitigate the potential future over-generation problems.

7.3. Sodium Sulfur (NAS) Batteries for Energy Time-shifting and Renewable Generation support

The development of NAS battery technology in Japan during the 1980s was because of the need for responsive, large capacity energy storage (e.g., multiple 10 MW blocks with 8 hours storage) distributed within metropolitan areas as an alternative to distant pumped hydro. NAS batteries are in the early stages of introduction to U.S. and global markets. Over 200 MW of NAS capacity have been deployed in Japan at installations up to 12 MW, each with nominal energy storage of 7 hours at rated power. American Electric Power (AEP) started operation of the first 1 MW unit in the U.S. in June 2006, and recently announced plans to acquire an additional 6 MW. Several other projects are under development in the U.S., including at California utilities.

To date, the most frequent application in Japan has been off-peak to on-peak energy delivery (also known as time-shifting or peak-shaving). However, recent emphasis on wind generation deployment to meet the Kyoto protocol has stimulated development of large systems for combined time-shifting and wind stabilization, brought on by a combination of Japanese geography and the usual diurnal mismatch between peak wind generation and peak load. Because premium wind resources are remote from load centers and separated by complex terrain in Japan, wind patterns are turbulent, and wind developers are required to stabilize output before connecting to the grid. Also, Japan has a large fraction of base-load nuclear power with few generation resources to provide off-peak load-following.

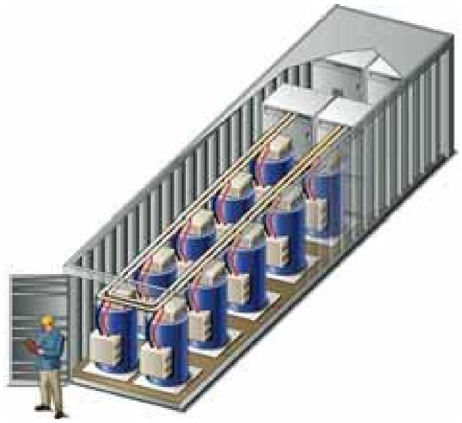
NAS installations will suppress short-term wind power fluctuations (similar to those associated with regulation control on U.S. grids), and time-shift off-peak generation to on-peak loads. Accordingly, the NAS installation appears to the grid as dispatchable load during off-peak intervals and as dispatchable generation during on-peak intervals. A 34 MW NAS installation rated at 245 MWh storage is under construction at Rokkasho Village in Northern Japan. Operation is scheduled for April 2008.

NAS battery applications in U.S. markets include combinations of regulation control, load-following; T&D upgrade deferral, time-shift renewables generation and reliability enhancement.

7.4. Use of Flywheel Technology for Additional Regulation

The CEC funded a field test in 2005-6 for a 100 KVA high-speed flywheel system in San Ramon on the California ISO-controlled Grid. The California ISO sent ACE signals to the unit to verify the unit's ability to provide regulation and frequency control services to the grid. This test was successfully concluded in early 2007. The system was highly reliable and met all the California ISO's performance standards.

The next step is the potential commercial installation of a 20 MVA flywheel system on the California ISO-controlled Grid and for the flywheel system to provide regulation services. A proposed 20 MVA Beacon Power high speed flywheel system is shown in the pictures on the next page:



KEMA was asked to evaluate the environmental impact of using flywheel technology for regulation services versus a conventional fossil fired power plant. Their report concluded "that flywheel-based frequency regulation can be expected to produce significantly less CO_2 for all three regions (of the country) and all the generation technologies, as well as less NO_x and SO_2 emission for all technologies in the California ISO region....When the flywheel system was compared against "peaker" plants for the same fossil generation technologies, the emissions advantages of the flywheel system were even greater."[31]

The flywheel system has a very fast dynamic response rate and can switch from full charge to full discharge in one second. This fast response rate and ramp rate make it an ideal technology for frequency and ACE regulation. The high availability of the system and high efficiency make it an excellent candidate for commercial deployment of the system. As new wind generation is added to the system and the amount of required regulation services increases, a 20 MW or 40 MW flywheel systems may be the best environmental choice for meeting the regulation needs.

7.5. New Storage Technologies

7.5.1. Hydrogen storage

Hydrogen storage is now being proposed as the answer to the need for new storage capability. It has the advantage of being easy to make as electrolysis is a tried and true method for separating water into hydrogen and oxygen molecules. The energy can be recovered by either using a fuel cell to recombine the hydrogen and oxygen or the hydrogen can be used as fuel in a steam boiler or combustion engine.

On May 8, 2006, DOE, NREL and Xcel Energy signed a two-year cooperative agreement for a "wind to hydrogen" research, development and demonstration project. The research will examine hydrogen production from wind power and the electric grid. The hydrogen will be produced through electrolysis (i.e., splitting water into hydrogen and oxygen using electricity from wind turbines). For storage, a new onsite facility will compress the hydrogen into containers. Later,

31 "Emissions Comparison for a 20 MW Flywheel-based Frequency Regulation Power Plant", KEMA Project:BPCC.0003.001 January 8, 2007 Final Report.

the hydrogen will be used to generate electricity either through an internal combustion engine or via a fuel cell. Xcel and NREL are each paying part of the two million budget for the project. The project commenced operation in December 2006 and operational results are to be released soon.

The main problem with hydrogen is storage. If hydrogen is compressed and stored in a high pressure tank, a lot of energy is required to compress it to 5,000 PSI, and a very large tank is required to hold a significant amount of hydrogen gas. This significantly lowers the efficiency of the process and makes hydrogen uneconomical for large amounts of storage. Cooling hydrogen to very low temperatures will reduce the volume of storage, but this makes the process even more uneconomical. New carbon nanotube technology has been proposed as a storage medium for hydrogen, and research on this technology is underway. "Carbon nanotubes are microscopic tubes of carbon, two nanometers (billionths of a meter) across, that store hydrogen in microscopic pores on the tubes and within the tube structures. Similar to metal hydrides in their mechanism for storing and releasing hydrogen, the advantage of carbon nanotubes is the amount of hydrogen they are able to store. Carbon nanotubes are capable of storing anywhere from 4.2% to 65% of their own weight in hydrogen."[32]

The US Department of Energy has stated that carbon materials need to have a storage capacity of 6.5% of their own body weight to be practical for transportation uses. Carbon nanotubes and their hydrogen storage capacity are still in the research and development stage. Research on this promising technology has focused on improving manufacturing techniques and reducing costs as carbon nanotubes move towards commercialization.

The DOE is sponsoring a major research project on hydrogen storage technology. The May 8, 2006 the DOE press release described a two-year DOE-sponsored research project to be performed for NREL and XCEL energy to evaluate the use of hydrogen storage in combination with wind generation. The field test facility was dedicated in December 2006. It is recommended that representatives from the California ISO, the CEC and the California utilities do a joint review of this DOE project.

The California ISO is a participant in a BPA sponsored research project on the use of storage technology to mitigate the changes to Area Control Error (ACE) in the two areas due to wind generation.[33] This is a joint project with Pacific Northwest National Labs (PNNL). The concept is to determine the portion of the ACE in each of the two balancing authorities that is being driven by the changes in wind generation. Next, combine the two ACE terms into a net ACE, then use high speed storage such as a flywheel system to dampen the change to the two systems. If wind is ramping up in one system and down in the other, the net change may be small and the interconnection frequency is not really being affected by the aggregate change in wind generation energy in the two areas. Obviously there are transmission constraints that have to be included in the new control system design. The final report on this concept is due by the end of 2007.

32 http://www.fuelcellstore.com/information/hydrogen_storage.html

33 "Wide-Area Energy Storage and Management System to Balance Intermittent Resources in the Bonneville Power Administration and California ISO Control Areas", BPA 00028087 / PNNL 52946.

7.5.2. Compressed air storage

Compressed air storage technology has been used in Iowa with some success. They took advantage of a large underground aquifer for the compressed air storage reservoir. A 1.5 MW wind turbine is used to both compress the air and inject it into the aquifer and for recovery of the energy that is fed back into the grid. To make much of a difference, there would need to be 50 or more of these units.

The CEC has contracted with EPRI for a Compressed Air Study for California to determine if the many abandoned gas and/or oil wells in the state could be used for compressed air storage. The report on this study is scheduled for release later this year

7.5.3. Flow batteries

Flow batteries create energy storage by using large tanks of a rechargeable electrolyte. The three types of flow batteries are zinc-bromine, vanadium redox that uses sulfuric acid, and sodium-bromide.

Flow batteries have low energy density, but they offer high capacity and independent power and energy ratings. Vanadium Redox Battery (VRB) installations offer up to 500 kW, 10 hrs (5 MWh). In 1991, Meidisha unveiled a 1 MW/4MWh ZnBr battery, and numerous multi-kWh ZnBr batteries have been built and tested over the years. So far, only relatively small flow battery systems have been installed in the U.S. The electrolytic material used in these systems is quite corrosive and environmentally challenging to site and permit.

A flow battery system is being proposed for the Santa Rita Jail in California. This project is a partnership with the jail, PG&E, Chevron Energy Solutions and VRB Power Systems. The objective is to develop a Microgrid demonstration project that includes a VRB flow battery. This project proposal was submitted to the DOE for funding in July 2007.

"The proposed Micro Grid Project includes the installation of a 1.5 MW VRB flow battery at the jail with six hours of storage capacity for a battery rating of 9 MWh capacity, a static transfer switch, and a generation monitoring and control system (e.g., CERTS). This environmentally-friendly battery, in combination with the existing fuel cell and PV systems, will have the capability of following the jail's electrical load and would provide sufficient generation capacity to provide approximately eight hours of the jail's full power needs. This will be accomplished without having to start the jail's diesel generators, thus reducing emissions. The jail's peak utility demand in 2006 was 2.3 MW when the fuel cell was not in service. With the fuel cell in service, the peak utility demand would be about 1.3 megawatts."[34]

The California ISO has agreed to be an advisor on the Santa Rita Jail project if it is funded by the DOE.

34 VRB project proposal "Santa Rita Jail AC Micro Grid System Demonstration Project Summary - June 21, 2007.

7.5.4. Super capacitors

Super capacitors or electrochemical capacitors, possess swift charge and discharge capabilities. More powerful than batteries, they can be cycled tens of thousands of times. Those with energy densities under 20 kWh/m3 have been successfully developed, and work is underway to expand the effectiveness of larger units.

7.5.5. Plug in Hybrid Vehicle-to-Grid (PHVG)

The idea of using the batteries of electric vehicles as an energy storage resource -- a concept called Vehicle to Grid (V2G) -- is still in its infancy, but may have potential as a quick-response, high-value service to balance fluctuations in load. Some experts predict that by connecting enough vehicles to the grid and transmitting power back and forth as needed, utilities could one day save billions per year.

7.5.6. Lithium-Ion battery storage

Lithium-Ion batteries have been successfully used in Japan for large amounts of electric energy storage. Their experience with a 34 MW NAS Battery System for the 51 MW Rokkasho Wind Park was reported at the EESAT 2007 Conference that was held in San Francisco, September 28. Lithium-Ion batteries have high power density and appear to be cost-effective for use with intermittent renewable resources.

7.6. Conclusion

The intent of this chapter is to highlight some of the current work in progress in the area of storage technology. The California ISO and the utilities need to work with the DOE and the CEC to follow the research in storage technology and to provide opportunities for testing and evaluating new storage technology in California. Storage will play an important role in California in the successful integration of large amounts of renewable energy in the future.

Storage facilities can provide a number of benefits that will help with the integration of large amounts of renewable resources. Storage provides a mechanism for saving off-peak energy production from wind generation and delivering the energy during on-peak periods. Some storage technologies can also provide Ancillary Services such as regulation and contingency reserves and reactive power for voltage support. The major barrier for construction of new storage facilities is not the technology but the absence of market mechanisms that recognize the value of the storage facilities and financially compensate the owners for the services and benefits they can provide. The California ISO plans to work with the IOUs, stakeholders, and potential providers of storage technology to design market products that properly compensate owners of storage facilities for the benefits they can provide.

7.7. Recommendations

- Initiate a California ISO project for storage technology with the goal of removing technical and economic barriers to the deployment of the technology.

- Hold stakeholder meetings and workshops to explore market mechanisms for financially compensating owners of storage facilities for the benefits they could provide such as regulation services, other Ancillary Services, transmission loading relief and voltage support. This is in addition to their ability to shift off-peak energy production to energy delivery on-peak.

- Work with the CEC and the DOE and the IOUs on evaluating storage technology and participate in field tests of the various technologies as appropriate.

Chapter 8 - National Experience

There have been numerous wind integration studies in the U.S., and some common themes have emerged from the published reports. Utilities that have some hydro generation resources can more easily accommodate the variability of wind generation. When the wind generation is high, the hydro systems can be backed down to accomodate the wind generation energy. The water is conserved behind the dams, and this essentially stores the renewable energy for delivery during times when the wind is not blowing. There are constraints on hydro systems; however, as a prescribed amount of water release is often mandated for fish, agricultural and environmental reasons. Utilities that depend on the fast ramping hydro systems for regulation lose some of the regulation capability if the units are forced down to minimum energy production levels to make room for the wind generation.

Utilities that have all their units scheduled on a block hourly basis and have a limited amount of regulation capability will also experience some difficulty in handling large amounts of intermittent energy production from wind generation. The combined variability of both load and wind generation can result in major system control problems if there is a limited amount of regulation available and the scheduled hourly energy production from other generating units cannot be changed. For example, coal fired generating plants do not change production levels easily and typically are not used to supply regulation services. Systems like ISOs and RTOs with market structures that enable them to redispatch units on a 5 to 15 minute basis will have a much easier time rebalancing as wind generation production levels change.

8.1. Major U.S. Studies on Renewables

8.1.1. Minnesota Wind Integration Study – 2006

This study evaluated the reliability and cost impact associated with increasing installed wind generation to 15%, 20% and 25% to serve customer load in Minnesota by the year 2020. Projected increase of wind generation is 4,500 MW. Four balancing authorities were included in the study – Xcel Energy, Great River Energy, Minnesota Power and Otter Tail Power. The study concluded that they could accommodate up to 25% (5,700 MW) of energy from wind generation resources without significant reliability and transmission congestion issues. They will need to increase the amount of regulation capacity by up to 20 MW, and their incremental operating reserve costs increase by $0.11 per MWh for the 20% wind generation case. Their total wind integration operating cost range for up to 25% wind energy delivered to their customers is less than $4.50 per MWh of wind generation.

8.1.2. New York State

The state commissioned a study on the impact of 3,300 MW of wind generation (10% of the New York State peak load). The results of this comprehensive study were published in 2005, and the report has been a model for how to do renewable integration studies. GE Energy was the consultant for this study. The results pointed out the importance of interconnection rules that require wind generation to meet Low Voltage Ride Through standards and voltage regulation criteria. The study also highlighted the importance of a reasonably accurate Day-Ahead wind generation forecast for scheduling of other generation resources and unit commitment. The financial impact of this forecast was very significant (millions of dollars annually) to the customers in New York if no wind generation forecast was available and generating units started that were not needed. The study also showed that the amount of additional regulation capacity needed was less than 40 MW, and no additional spinning reserves were needed.

8.2. Western Regional Coordination of Strategies on Renewables

BPA and the California ISO have agreed to work together on issues of common interest related to integration of renewables. Particular emphasis is on policy setting with regard to wind development. There is already cooperation and collaboration on technical issues, but more needs to be done to shape policy issues on renewables in the West.

Key strategic issues should include sharing of information on generator interconnection queues and forecast imports and exports of renewables between balancing authorities. This would facilitate improved transmission planning so the energy can be moved between areas with minimum congestion issues.

A second issue is the need for common and consistent interconnection agreement language so wind generators and other renewables will receive common treatment in all areas. This working group can create a template for interconnection agreements with wind generation that combines the best features from each company.

8.3. Northwest Wind Integration Action Plan

The Pacific Northwest Wind Integration Plan was published in March 2007. This report was a major collaborative effort of all the Pacific Northwest utilities with BPA one of the leaders of the effort. A summary of this report follows.

8.3.1. There are no fundamental technical barriers to operating 6,000 megawatts of wind in the Pacific Northwest.

There is a range of estimated costs associated with integrating wind into the Northwest power system. When wind energy is added to a utility system, its natural variability and uncertainty is combined with the natural variability and uncertainty of loads. As a result, there is an increase in the need for system flexibility required to maintain utility system balance and reliability. The cost of wind integration starts low, particularly when integrating with a hydro power system that has substantial flexibility, and then rises as increasing amounts of wind are added. Locating wind resources in geographically diverse areas can help reduce costs. Ultimately, costs plateau at the cost of integrating wind with natural gas power plants.

The preliminary cost estimates for integrating 6,000 MW of wind power are based upon existing levels of system flexibility. Load growth and other competing uses for that flexibility, and possible further constraints on system operations, will diminish the supply and increase the cost of wind integration services.

With increasing amounts of wind, there will likely be times when large, unexpected changes in wind output (so-called "ramping events") coincide with periods of limited hydro flexibility. Initial analyses indicate that these will be low probability events, but if other sources of flexibility are not available at the same time, system operators will need to limit wind output for brief periods in order to maintain reliability. The Federal Energy Regulatory Commission now requires wind plant operators to help maintain system reliability. Northwest utilities and wind developers are collaborating to implement the requirement in a mutually-satisfactory and cost-effective manner.

8.3.2. Wind energy is providing value to Northwest electricity consumers, but the Northwest will still need other resources to meet peak loads.

The fundamental value of wind to a utility's portfolio is its ability to provide energy to displace fossil fuel consumption, limit exposure to uncertain and volatile fuel prices, and hedge against greenhouse gas control costs. Because wind is primarily an energy resource with relatively little contribution to meeting system peak requirements, the Northwest will need to build other resources with greater capacity value to meet growing peak loads.

8.3.3. In the short-term, there is available transmission capacity to integrate additional wind resources – but this is not expected to last for long.

New transmission will be needed to support growing loads and resource additions and can facilitate the opening up of new areas for wind development, helping to diversify wind production. This diversity helps smooth variability and therefore lowers the cost of wind integration. Because of the limited contribution of wind to meeting system peak requirements, traditional models for transmission development and marketing should be altered to achieve greater economic efficiency. A more economical and efficient approach for a resource such as wind is to provide a mix of firm, non-firm and conditional firm transmission that achieves a balance between the cost of transmission capacity and the value of delivered wind energy. Cooperation among transmission planners, regulators, utilities and the wind development community is essential to create a workable model for planning, financing and marketing transmission for wind energy.

8.3.4. The major portion of wind integration costs are due to the need for additional flexible resources to balance loads and resources in Real-Time in order to accommodate wind variability.

Balancing authority operators must have sufficient flexible generating capacity or load management options available to accommodate load and wind variability to ensure that reliable service will be maintained. There should also be provisions for equitable recovery of the associated costs.

8.3.5. Steps can be taken to increase integration capability and lower integration costs.

The cost of wind integration services can be reduced through four general types of actions: 1) developing more cooperation between regional utilities to spread the variability of wind more broadly; 2) developing markets that will reward entities that choose to market their surplus flexibility; 3) making more low-cost flexibility available, such as that provided by hydroelectric resources; and, 4) development and application of new flexible technologies. Achieving these goals will require coordinated actions similar to those required to establish the Pacific Northwest Coordination Agreement of the Columbia River Treaty. Fortunately, the region has a long history of forging cooperative agreements designed to increase the size of the pie for all regional consumers. These agreements can provide a model for what will be needed over the next several years to address wind integration issues.

Chapter 9 - International Experience

The experiences from Europe and other countries with significant amounts of wind generation and other renewables can provide some valuable insights on the issues and solutions that could be adopted in California. Island systems, such as Ireland and Australia, have greater challenges with larger amounts of wind generation than countries that are part of a large interconnected system like Spain and Germany. The CEC IAP report included a section "Review of International Experience Integrating Variable Renewable Energy Generation". This report and additional information from company web sites, presentations at various conferences and published papers are the sources for the material in this chapter.

9.1. Spain[35]

While the European countries have led the electric industry with the development of wind, Spain (the second largest wind producer in Europe[36]) has been contending with issues on a scale equivalent to the California ISO. In 1996, Spain had 164 MW of installed wind generation. As of November 2006, the country had more than 11,000 MW of installed capacity on a 43,700 MW peak system. By 2010, it is anticipated that Spain will have more than 20,155 MW of installed wind generation on their grid.

The large amount of integration of wind generation prompted the Spanish TSO Red Eléctrica de España, S.A. (REE) to develop a three-pronged strategy focusing on sophisticated wind forecasting tools, wind farm connection standards and dispatchability of the wind farms.

9.1.1. Spain's forecasting tools

Wind producers in Spain are entitled to deliver electricity to the grid via the wholesale market or a distributor, as long as it is technically possible. In either case, the wind parks are required to provide a wind forecast to REE. With the large amount of variable wind energy production being placed into the electrical system, a more precise forecast regimen was required. In 2002, REE started to develop an hourly forecasting system that delivered forecasts up to 48 hours in advance. Using data from the wind parks for the various areas throughout the peninsula, REE was able to create and use a high quality forecast system that could focus on any size region within the country. REE was able to reduce their 48 hour percent mean relative error from almost 40% in 2005 to approximately 26% in 2006. For both years, the percent mean relative error for the less than 5 hour look ahead was less than 15%. They have achieved these values by applying a continuous improvement process to the forecast system.

35 Adapted from "Large integration of wind power: the Spanish experience, Juan M Rodriguez-Garcia, Tomás Dominguez,Juan F, Alonso and Luis Imaz. IEEE PES 2007 Tampa FL
36 energyBiz August 2007

9.1.2. Spain's wind park connection standards

Spain has recognized the potential problem of large amounts of wind integration in regard to stability conditions under system faults.

In accordance with Spain's technical standards for interconnection, it was mandatory to install three instantaneous minimum voltage relays between the phases in the connection of the wind park. The relays must provide for instantaneous disconnection of the park when voltage drops below 85% of the average value between the phases. Studies were carried out to show the importance of a minimum voltage protection system and system stability. The original studies showed that there was little problem with a short circuit when a small amount of wind production was on-line. But if a short circuit occurred on a day with high wind production, obviously the amount of power being disconnected would result in a serious loss of generation, which would greatly increase the risk to grid integrity.

Looking at this threat to grid integrity, REE undertook a transient stability study of the response of wind energy to fault-caused voltage dips in order to determine the maximum wind production of the Iberian Power System in peak and off peak conditions. The result of the study defined the voltage ride-through requirements and the permissible active and reactive consumption values during voltage dip situations.

9.1.3. Dispatchability of the wind parks in Spain

Because of the large integration of wind, REE determined that two important operational issues needed to be addressed to guarantee the integrity of the grid. The issues are as follows:

- The current condition and Real-Time data of the wind facilities
- How to coordinate the dispatch of wind generation to match system conditions

REE established a Wind Generation Control Center (WGCC) that was integrated with their Control Center. The WGCC is a dedicated desk that is available 24 hours a day, 7 days a week and is responsible for collecting and providing the Real-Time data on the wind facilities to the Control Center, and in turn, providing the dispatch instruction from the Control Center to the wind parks.

9.2. Germany

Germany currently has more than 20 GW[37] of installed wind generation capacity and they expect to have 36 GW installed by 2015[38]. The majority of the wind generation facilities are in northern Germany, although some wind facilities are spread throughout the country. The four German transmission system operators (TSO) must take all the energy produced by the wind generators, and they all share the balancing error in accordance to their market share.

37 CEC PIER Project Report, April 2007, "Review of International Experience Integrating Variable Renewable Energy Generation", page 1
38 "Integrating Wind Energy into Public Power Supply Systems – Germany State of the Art" by Reinhard Mackensen, Bernhard Lange, Florian Schlogl; Institut fur Solare Energieversorgungstechnik e.V.

Therefore, the TSO with the largest amount of wind generation capacity does not have to do all the rebalancing of the system based on the wind generation variability in its area.

Wind power forecasts are essential to their operation. They forecast wind energy production 72 hours in advance for setting up their energy schedules, and then use short-term forecasts up to 8 hours in advance of Real-Time operating decisions. The TSOs communicate the data from the wind generation facilities every 15 minutes and update the 72 hour wind generation forecast twice a day. They do not receive data from all the wind farms, so they use modeling and scaling methods to fill in the missing data.

Germany does not use "Net Metering" as is used in the U.S. for wind generation that is installed on the grid. This means they separately meter the energy production from wind generation, and they pay a premium for renewable energy that fits the load profile. The price differential between what load is charged and what the generation from renewables is paid may be significant. For example, load may be charged $0.10 per kWh and wind generation paid as much as $0.40 per kWh if the wind energy production coincides with the peak load period. The German Renewable Energies Act grants a fixed feed-in tariff for each kWh produced by Renewable Energy Sources(4).

9.3. Ireland

As of June 2005, ESB National Grid for Ireland had 383 MW of wind generation connected to the grid and 575 MW of additional wind generation planned. Ireland is an island system, and they cannot lean on a large interconnected grid to help them with the integration of large amounts of wind generation. To ensure they can continue to operate the grid reliably, they have performed in-depth studies on the impact of large amounts of wind generation on their system. In July 2004, they published their interconnection standard document WFPS1 (Wind Farm Power Station Grid Code Provisions). This document describes their Low Voltage Ride Through, voltage control and frequency response requirements. They are particularly concerned with frequency issues and how to limit ramp changes from wind parks. They also recognize that wind generation is an intermittent resource and cannot be counted on to meet peak load demands. They have concluded that they need an additional 85 MW of fossil fueled generation (operating reserves) for every 100 MW of wind generation to ensure they have sufficient generation to meet their load. Ireland represents one extreme in the issues associated with integration of large amounts of wind generation on the grid.

9.4. Denmark

Denmark currently has more than 2,000 MW of installed wind generation capacity. Its goal is to increase the amount of wind generation to 5,500 MW, which is equivalent to 50% of the total electric demand for Denmark. Most of the current generation capacity is from small units that are less than one MW each. The units are widely distributed throughout the country, with the largest concentration in western Denmark. Many of the wind generators are connected to the distribution system rather than to the transmission grid. The goal is to replace many of these small turbines with new larger units over the next five years. Denmark can handle the large amount of wind generation because of its transmission ties to Norway, Sweden and Germany. Hydro systems in the Nordel Pool provide much of the regulation required as well as providing operating reserves to Denmark. The 15 minute variability of the wind generation production is relatively small at approximately 8%, which enables them to forecast and schedule wind energy on an hourly basis. The one lesson learned from Denmark is the value of having strong ties to neighboring areas, especially those with a lot of hydro generation, to mitigate the intermittence of energy production from large amounts of wind generation.

9.5. Canada

9.5.1. BC Hydro

BC Hydro currently has 11,000 MW of generating capacity of which 90% is from hydro generation. It does not currently have any installed wind generation capacity but British Columbia Transmission Company (BCTC) currently has 700 MW of wind generation in its interconnection queue. The northwestern coastal area of British Columbia has a lot of potential wind generation, but BCTC will have to build some major new transmission to this area before it can be developed. The long-range energy plan for the province is to develop wind generation to meet its load growth and to export significant quantities of the renewable energy to the western area of the U.S., especially California.

9.5.2. Ontario's Independent Electricity System Operator (IESO)

IESO currently has 400 MW of installed wind generation capacity. IESO commissioned a wind integration study by AWS and GE to assess the impact of 1,300 MW of wind generation on their system. Their study concluded that Ontario has significant wind generation potential and it could provide more energy in the winter than in the summer. Wind generation forecasting is critical for reliable operations as the amount of wind generation capacity increases. IESO also concluded they can handle up to 5,000 MW of wind generation without a serious impact on their operations. This is on a system with 33,100 MW of installed generation capacity, of which 23% is hydro giving them the needed operational flexibility. They also do extensive interconnection analyses for each proposed wind generator to verify the voltage control and transient stability requirements and the potential need for Special Protection Schemes.

9.5.3. Manitoba Hydro (Manitoba)

Manitoba is a predominately hydro generation system with more than 5,000 MW of hydro generation capability. As a 95% hydro system, they can use the hydro resources to store wind generation production in off-peak periods and then deliver it at on-peak periods. They currently have less than 100 MW of wind generation, but expect to add 300 MW in the next several years. They calculate their wind integration cost at between $0.05/kWh and $0.06/kWh. Their business strategy is to export most of this wind generation to U.S. utilities in the Midwest that need to buy renewable energy to meet their state's RPS goals. Manitoba's strategy clearly shows the value of hydro generation resources for storing and shaping an intermittent resource such as wind generation and delivering it to meet daily peak loads.

9.5.4. Alberta Electric System Operator (AESO)

AESO has 443 MW of wind generation out of 13,223 MW of installed generation capacity. Of this total, 81% is gas or coal-fired units, with only 899 MW of hydro generation. They have established a 900 MW ceiling for wind generation at this time, but have applications for 3,800 MW of new wind generation capacity. They have elected to limit the amount of wind generation until they have completed additional studies on the impact of large amounts of wind generation on their system. They are concerned about how their system will be able to meet the large ramps typically associated with large amounts of wind generation. They also have some major transmission planning work to do to move the renewable energy from the generation sites to the load centers.

9.5.5. Hydro Quebec

Hydro Quebec's generation resources are 92% hydro (32,000 MW) with wind generation of 322 MW. Obviously, with this much hydro generation, the intermittence of wind generation is not an issue. Hydro Quebec's goal is to have 4,000 MW of wind generation installed by 2015 and then to maintain a 10% wind/hydro generation ratio. They are concerned that their traditional hydro schedules to serve their load will have to change. They are focused on better forecasting tools and improved modeling of the wind generation facilities.

9.6. Conclusions

There are significant lessons that can be learned and strategies that can be adopted based on the experiences of these international transmission operators. The California ISO needs to learn more about Germany's technique for sharing the system balancing requirement between the four TSOs. Spain has made significant progress in forecasting their wind energy production and has implemented strict interconnection rules. Ireland has implemented ramp limits to mitigate the problem with large ramps from wind generation resources. Canadian utilities have the advantage of having significant hydro generation resources that will reduce their integration problems, and some of their tools and strategies should be adopted where feasible.

Chapter 10 – Conclusions and Recommendations

This report describes many conclusions and recommendations made by the Renewables Workgroup. The key conclusions and recommendations are:

1. It is essential that the new transmission facilities planned for the Tehachapi area be permitted and built on schedule. These transmission upgrades are essential for the interconnection of all new generation planned for this area and for the delivery of the renewable energy to serve customer loads.

2. The amount of regulation resources, fast ramping resources and load following or supplemental energy dispatches will significantly increase due to the additional intermittent resources planned to meet the 20% RPS.

3. Accurate Day-Ahead and Hour-Ahead forecasts of wind and solar generation energy are essential for reliable operation of the power grid and for decisions on procurement of the optimum amount of regulation resources and operating reserves. Linkage of wind and solar generation forecasts with MRTU will provide more accurate Day-Ahead generation schedules which will help to reduce dispatch notices to fossil fueled units for hours when they are not needed. It will also help to reduce over-generation problems due to load and generation schedule mismatches.

4. Deployment of additional storage facilities would significantly enhance the integration of renewables. New storage technology can provide some of the fast ramping and additional regulation resources that will be required. They can also provide reactive power for voltage support and, depending on their location, they can mitigate transmission congestion and line overloads. Large storage facilities can absorb off-peak energy production from wind generation resources and deliver the energy during peak load hours. Storage facilities have the added advantage of being "green" resources as they do not directly contribute any greenhouse gases.

5. The California ISO must continue to monitor other studies and reported experiences on integration of renewables. While each area has some unique characteristics due to their geographic, topological, and metrological circumstances, the California ISO can also learn from the experiences of these other areas. Also, the European countries have installed substantially more wind generation resources than all of the United States and the experiences gained by these countries can greatly benefit the California ISO.

The California ISO is committed to the successful and reliable integration of renewable resources. The integration of renewables is being escalated to a formal project status in 2008 and a new Project Manager will be selected to lead this effort. One of the first tasks for the new project team will be to prioritize what work has to be done and to identify the resources required and create a detailed project schedule. An additional key question is the need for a study of the impact of a 33% RPS.

The Renewables Workgroup has identified the following list of tasks and questions that it recommends be addressed to meet the 20% RPS.

Task 1. Develop New Ramp Forecast and Planning Tool for Real-Time Operations

The output from wind and solar generation can change dramatically, both up or down, in a very short period of time. These rapid changes pose a significant challenge to system reliability and to the grid operator who must meet NERC and WECC Reliability Performance Standards. Better forecast and planning mechanisms, especially on a micro-climate basis, will enable the California ISO to mitigate the operational problems that otherwise arise from rapid swings in generation or load, both up and down. The purpose of this task is to use that information and the answers to the questions below to develop a new ramp forecast and ramp planning tool for Real-Time operations. The goal is to have a prototype of the tool ready in 2008 for testing and evaluation. The production version of the tool must be ready in 2009 to coincide with the expansion of wind and solar generation installed on the system.

Key questions are:

1. How can ramps be accurately forecast? What are the best forecast sources and what meteorological data is required? Does Weather Bank provide sufficient forecast information with sufficient geographical granularity, or does the California ISO need additional data and another forecast service?

2. Does the California ISO need to have a person "on shift" to assess weather patterns and forecast ramps due to intermittent renewable resources?

3. Does the California ISO need a Doppler radar system in major wind-generation areas (e.g., Tehachapi) to see approaching weather fronts? Would Sound Detection and Ranging (SODAR) be more cost effective? What has been the experience of others in detecting major weather fronts?

4. Who needs the ramp data? Real Time operations? SCs? Wind generator operators? Others?

5. How far in advance does the California ISO need to forecast ramps? A few hours? Day-Ahead?

6. How should the ramp information be made available to Real-Time operations? What is the impact on EMS? Plant Information (PI) Displays? Other?

7. What are the specifications for a Ramp Planning Tool to assist the operators in anticipating the dispatch notices that will be required to either start quick-start units or to shut down units?

Task 1.1. Ramp Mitigation Strategies

What are the optimum strategies for mitigating large ramps? Not all ramps are bad. A ramp up of solar energy in the morning period when the wind generation energy is ramping down could result in a net ramp that is very manageable. Ramp ups of energy production during the morning "load pull" could be very helpful. Therefore, an important consideration is to determine during which periods of the year and which hours of the day action needs to be taken to mitigate a large ramp up or large ramp down.

Key questions are:

1. What are the criteria for initiating ramp mitigation actions?

2. Some balancing authority ask wind generators to limit their "ramp up" production to a specific number of megawatts/minute. Is this a practical strategy? Could that strategy also be applied in the downward direction by advance curtailment of wind generation in anticipation of the decreasing wind so that a sudden downward ramp could be avoided? How would the California ISO decide what is the ramp limit? How would this information be sent to the wind generator operators? How would the ramp limits be allocated between all the different wind farms?

3. Is there a transmission limitation criterion that should also be considered such that the California ISO would have a different limitation for various areas of the system (e.g., SP 15 versus NP 15, areas west of Devers, south of Tehachapi, etc.) and what would be the justification for this difference?

4. Are there other strategies that could be used to mitigate the impact of ramps? Use of hydro resources, pump storage or other types of storage to rapidly ramp up or down for smoothing the ACE? Should the California ISO pursue the use of mid-hour intertie schedule changes? Should these be translated into one or more market products?

5. What will the dispatch notices look like for the other generators if the California ISO does not have a ramp mitigation strategy and what is their expected response?

Task 2. Over-Generation Problems

This Report describes the over-generation problem in some detail. Wind generation areas such as the Tehachapi characteristically produce maximum energy at night when loads are low. In the spring, when California has maximum hydro generation conditions due to snow melt in the Sierra, the wind generation production is often at its maximum. At times, this results in over-generation condition even with the limited amount of wind generation currently installed in the area. As the amount of installed wind generation capacity rapidly increases in the next several years, the over-generation problem will grow. The purpose of this task is to review the existing procedure for handling over-generation conditions and determine if it needs to be modified to implement pro-rata cuts for wind generation production.

Key questions are:

1. Does procurement of additional regulation solve the problem?
2. Are accurate P_{min} numbers available for all generation resources?
3. How many megawatts of “Must Take” generation are on the system?
4. If the California ISO sends dispatch notices to wind generators to curtail some production, what is the time lag that should be expected between the sending of the notices and the reduction of wind generation production?
5. Are there operators at the wind plants on a 24/7 basis to respond to the dispatch notices?
6. Is the estimated amount of wind generation curtailment (800 MW for less than 100 hours per year) accurate, and what are the consequences for doing these pro-rata cuts?
7. How much of the problem is solved by MRTU?

Task 3. Improve Accuracy of Day-Ahead Energy Forecasts for Wind Generators

The California ISO needs accurate Day-Ahead forecasts on the amount of wind generation energy production that can be expected for each hour of the next day. This information is an essential component in the decisions about the procurement of resources to meet demand as well as decisions about operating reserves and regulation resources and the dispatch notices for generator start-up. Previous studies (NYISO) have shown that savings of $100 million a year are possible by having a reasonably accurate Day-Ahead forecast of wind generation energy production. The purpose of this task is to procure a wind generation forecast service that can provide the most accurate forecasts possible for use in the MRTU Day-Ahead Market.

Task 3.1. Access the accuracy of current Day-Ahead forecasting technology.

Review the accuracy of the Day-Ahead forecasts supplied by AWS Truewind for each of the wind generation areas. Review the accuracy of Day-Ahead forecasts for other balancing authorities such as ERCOT in Texas, NYISO and BPA. Review the accuracy and adequacy of the metrological data for each of the wind parks. Assess whether the forecast data or the forecast models or both are the source for any inaccuracies in the Day-Ahead wind energy forecast for each wind park.

Task 3.2. Research new Day-Ahead forecasting tools.

Review the CEC-sponsored research on forecasting tools that was published in June 2006. The research team included EPRI, AWS Truewind and UC Davis. They explored the accuracy of different types of wind generation forecast models. The preliminary conclusion was that the research team had made a significant breakthrough in improving the accuracy of both 5-7 Hour-Ahead forecasts and Day-Ahead forecasts. Additional work is needed to validate the results with a prototype-forecast tool. The results from this task are to produce a set of recommendations for the scope of work for any additional research that is needed so they can create a final specification for a commercial grade Day-Ahead forecasting tool.

Task 3.3. Move forward with the acquisition of a Day-Ahead forecasting service.

Develop a Request for Proposal for a Day-Ahead wind generation forecasting service. The forecast should include total energy production from all wind generation facilities and the forecast energy production from wind generation areas. The ideal forecast would also have a breakdown by generators in the PIRP program. If the decision is to use two or more forecast services, then the recommendation must include the expected benefit of using more than one supplier and how the multiple forecasts should be combined into a final forecast for the MRTU Day-Ahead Market.

Task 4. Improve Accuracy of Same Day Energy Forecasts for Wind Generators

MRTU will require the PIRP generators to enter their forecast energy in the Hour-Ahead Scheduling Process (HASP). The current PIRP wind generation scheduling process requires a wind generation forecast nearly 3 hours in advance of the Real-Time operating hour. Under the MRTU HASP program, the time frame is shortened to 75 minutes before the start of the Real-Time operating hour. This much shorter lead time means that an advanced persistence forecast program may be as accurate, if not more accurate, than other more sophisticated forecast models such as neural network programs. The purpose of this task is to explore all options for improving the same-day hourly forecasts for both PIRP and non-PIRP wind generators and to consider whether the PIRP program should be changed under MRTU. If the program is to be changed, this will probably require a tariff filing.

Key questions are:

1. If a persistence model is the best option for 75 minute forecasts/schedules, should the wind generators do their own forecast? Does the California ISO need a commercial forecasting service going forward or could it do the forecasts internally?

2. How much in advance of the HASP scheduling point can the SCs for the wind generators forecast energy production so they can sell the uncommitted energy? Is this an issue?

3. The California ISO needs a 5-hour forecast, which is used to make market and reliability decisions on dispatch instructions to quick start units. Obviously, if the energy from wind generators will be below the original Day-Ahead forecast and energy schedule, the California ISO will need additional energy in the operating hour. If there are insufficient reserves and supplemental energy available to fill in the deficiency, then the California ISO must call upon quick start units to start up and provide the needed energy. If there

is an excess of energy forecast, there is still time for SCs to find buyers for the excess energy and set up the exports for the Real-Time operating hour. The California ISO will also have sufficient time to look ahead and plan alternate strategies for the Real-Time operating hour. Does this argue for retention of a commercial forecast service as persistence forecasts cannot provide an accurate 5 hour forecast?

4. Should the California ISO use the same forecast tools for this 5-Hour-Ahead forecast that it uses for the Day-Ahead forecast or is a different tool needed?

5. What are the operational and maintenance related concerns for maintaining two forecast tools? Does the California ISO maintain two separate forecast tools, and if so, when should it switch from one to the other?

Task 5. Develop New Graphical Displays for Real-Time Operators

PI displays can tell the operators what wind generation energy production is at that moment but they do not include the forecast of what wind will do in the next new minutes or hours. With forecasts for five or more wind park areas, there is both local data and aggregate data. The aggregate data and ramp forecast data impact the generation dispatcher the most. The transmission dispatcher is more affected by the local generation and the amount of energy that will flow on the transmission networks. The CEC has offered to fund some research work on this question, so this task may involve developing a detailed scope of work to secure the funding. They may identify some experts/consultants who could help the California ISO research and prototype the best man/machine interface for display of this information for the operators. The purpose of this task is to develop prototype displays for Real-Time operations that show actual energy production and forecast energy production of wind generation.

Key questions are:

1. How far in advance does the forecast energy production need to be for the operators? Minutes? 15 minutes? 1 hour? 2 hours? 5 hours?

2. How should the wind generation forecast production information be supplied to the Real-Time operating personnel?

3. Does the California ISO need graphical displays and if so, how should these displays look?

4. Is it important to see weather data for these areas as well as the actual energy production and forecast production?

5. What decisions are affected by knowing the forecast energy production?

Task 6. Link Renewables Forecast with MRTU

Once the Day-Ahead and same day forecast tools have been validated, the next question is how to link this information with MRTU. The forecast wind generation will be a key ingredient for the RUC process. The purpose of this task is to document what the information flow process should be and to test how it will be used in the RUC process.

Key questions are:

1. How should the forecast information be provided and who will use it?
2. Will the forecast information be used by the SCs for Day-Ahead schedules?
3. Which MRTU systems will be affected if any?
4. What is the flow of information, what decisions will result and how will the information be used in settlements?
5. What reports will need to be generated?

Task 7. Scheduling/Managing Imports and Exports of Renewables

California may not have enough locations for new wind generation and other renewable resources within the state for the IOUs to meet their RPS obligation. The IOUs are considering imports of wind generation from Oregon, Nevada and other western states. The purpose of this task is to establish the rules and procedures for facilitating these imports.

Key questions are:

1. Should imports of intermittent resources be dynamically scheduled?
2. Who will have the obligation for shaping and firming?
3. Are there limitations on how much intermittent energy can be accepted? Is the amount of regulation in southern California one of these limitations?
4. Is there anything special the California ISO should do for scheduling and tagging imports and exports of renewables?
5. Should the tolerance band be changed for dynamic schedules?
6. Should the California ISO request the sending balancing authority to share some of the regulation burden?
7. Should the SC that is buying the non-shaped energy be charged for the additional regulation burden? If so, how will the associated cost be determined?

During periods when the California ISO has over-generation conditions, it is definitely interested in exporting some of this excess energy. Whatever rules and procedures it imposes for imports will probably apply for exports, so it needs to make sure there are no unfair burdens on imports and exports.

Task 8. Impact on Resource Adequacy

Develop new models and scenarios to determine the "best fit" generation portfolio for integration of large amounts of renewables. How many MW of short start units will be required? What additional generation and storage facilities will be needed? How can this information be shaped to help guide the CPUC RA requirements?

Task 9. Modeling of Wind Generation Facilities

The current power flow and transient stability models stop at the point of interconnection of the wind farm. The actual performance of the wind generators and the sub-transmission collector systems is ignored. Other countries, such as Ireland, have found it essential to include actual models of the wind generators in their power system studies. The California ISO requested the CEC fund a new R&D study that improves the modeling of these facilities. This project has been approved and the kickoff meeting was held in August 2007. The purpose of this task is to recognize the commitment of California ISO resources to the technical and project advisory groups for this R&D project. The results will be new models that can be used in the transmission planning tools such as transient stability programs.

Task 10. Changes to PIRP II for Hour-Ahead Forecast and Scheduling

Add solar generation resources to PIRP. Develop new forecast models for concentrated solar resources so they can be included in the PIRP program.

Glossary of Acronyms

ACE	-	Area Control Error
ADS	-	Automatic Dispatch Signal
AGC	-	Automatic Generation Control
ALFS	-	Automated Load Forecasting System
AVR	-	Automatic Voltage Regulator
BPA	-	Bonneville Power Administration
CAISO	-	California Independent System Operator
CEC	-	California Energy Commission
CPUC	-	California Public Utilities Commission
DAM	-	Day-Ahead Market
DFIG	-	Doubly Fed Induction Generator
DOE	-	Department of Energy
DOP	-	Dispatch Operating Point
DPG	-	Data Processing Gateway
EMS	-	Energy Management System
EPRI	-	Electric Power Research Institute
FERC	-	Federal Energy Regulatory Commission
HASP	-	Hour-Ahead Scheduling Process
HVDC	-	High Voltage Direct Current
IAP	-	Intermittency Analysis Project
IFM	-	Integrated Forward Market
IOU	-	Investor Owned Utilities
LFE	-	Load Forecast Error

LGIP	-	Large Generator Interconnection Procedures
LSE	-	Load Serving Entity
LVRT	-	Low Voltage Ride Through
MRTU	-	Market Redesign and Technology Upgrade
MVWG	-	Modeling and Validation Workgroup
NERC	-	North American Electric Reliability Corporation
PDCI	-	Pacific Direct Current Intertie
PG&E	-	Pacific Gas and Electric Company
PIR	-	Participating Intermittent Resource
PIRP	-	Participating Intermittent Resources Program
PNNL	-	Pacific Northwest National Lab
RMR	-	Reliability Must-Run
RPS	-	Renewables Portfolio Standard
RTED	-	Real-Time Economic Dispatch
RTM	-	Real Time Market
RTUC	-	Real-Time Unit Commitment
RUC	-	Residual Unit Commitment
SCE	-	Southern California Edison
SCUC	-	Security Constraint Unit Commitment
SDG&E	-	San Diego Gas and Electric Company
STUC	-	Short-Term Unit Commitment
SVC	-	Static Voltage Compensation
VRB	-	Vanadium Redox Battery
VSTLP	-	Very Short Term Load Predictor
WECC	-	Western Electricity Coordinating Council
WGMG	-	Wind Generator Modeling Group
WTG	-	Wind Turbine Generator

Appendices

Appendix A – Study Results
Appendix B – Study Methodology
Appendix C – Load Forecasting Error Analysis
Appendix D – Wind Generation Forecast for the 20% RPS
Appendix E – Wind Forecast Error
Appendix F – Wind Generation Turbine Modeling
Appendix G – Tehachapi Transmission Plan
Appendix H – Transient Stability Plots

References

1. CPUC Report, November 1, 2005 "Achieving a 33% Renewable Energy", by The Center for Resource Solutions Team.

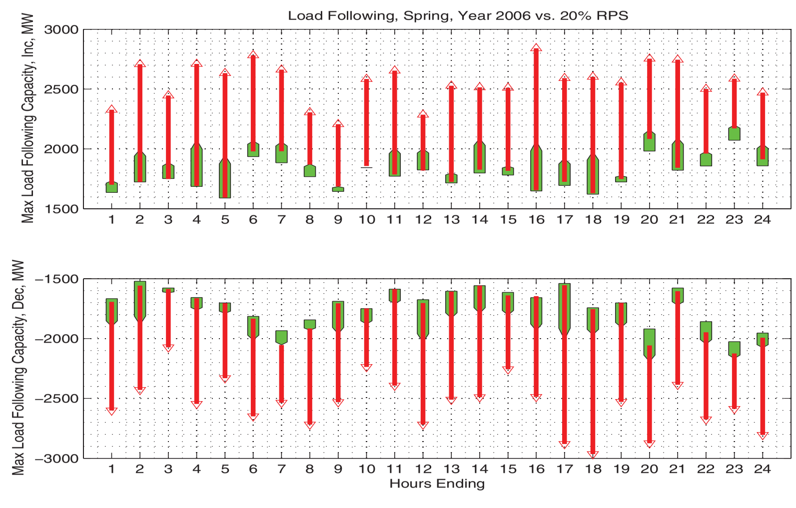
2. CEC PIER August 15, 2006 workshop on Intermittency Analysis Project: 2010 (1_YEN-NAKAFUJI_PORTER_2006-08-15.pdf).

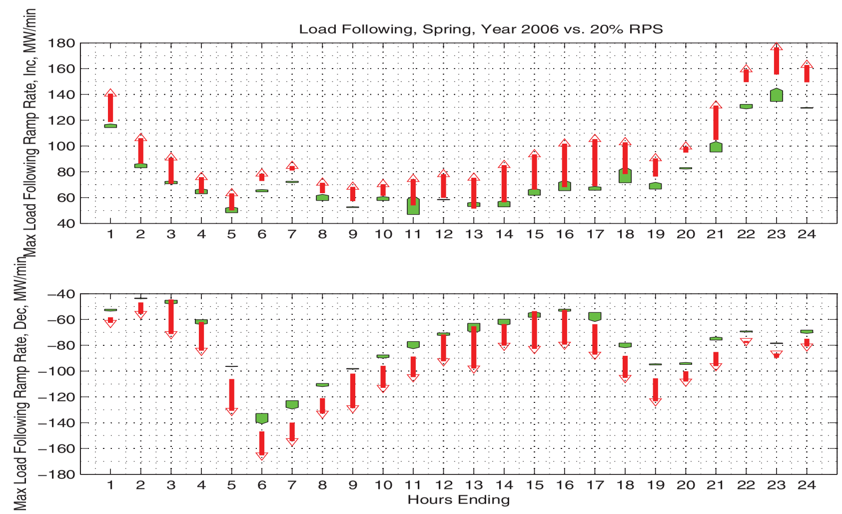
3. "Impact of Past, Present and Future Wind Turbine Technologies on Transmission System Operation and Performance" CEC PIER Project Report; May 2006 CEC-500-2006-050.

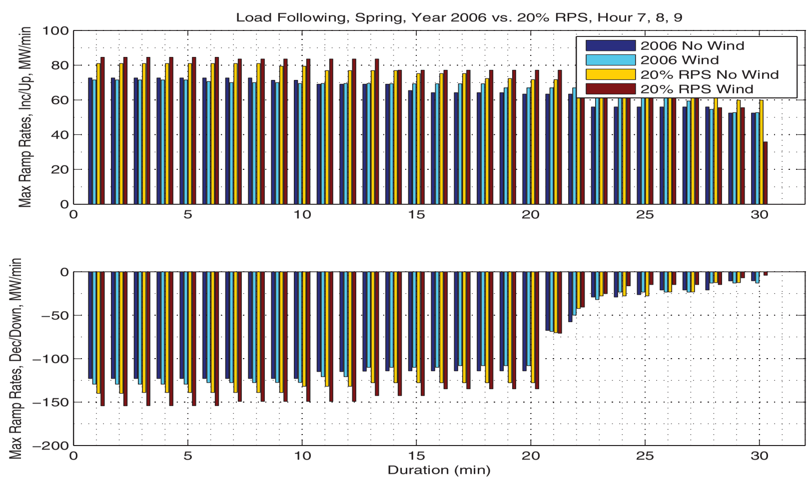
Appendix A – Study Result

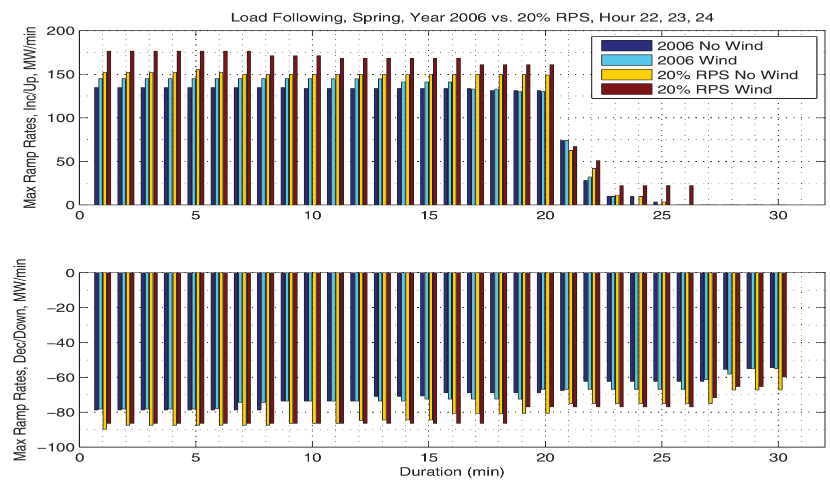
Spring: Load Following Capacity, Ramp Rate and Ramp Duration

The green arrow represents 2006. The red arrow shows the expected 20% RPS increase due to wind only. The tail of the arrows corresponds to no wind.



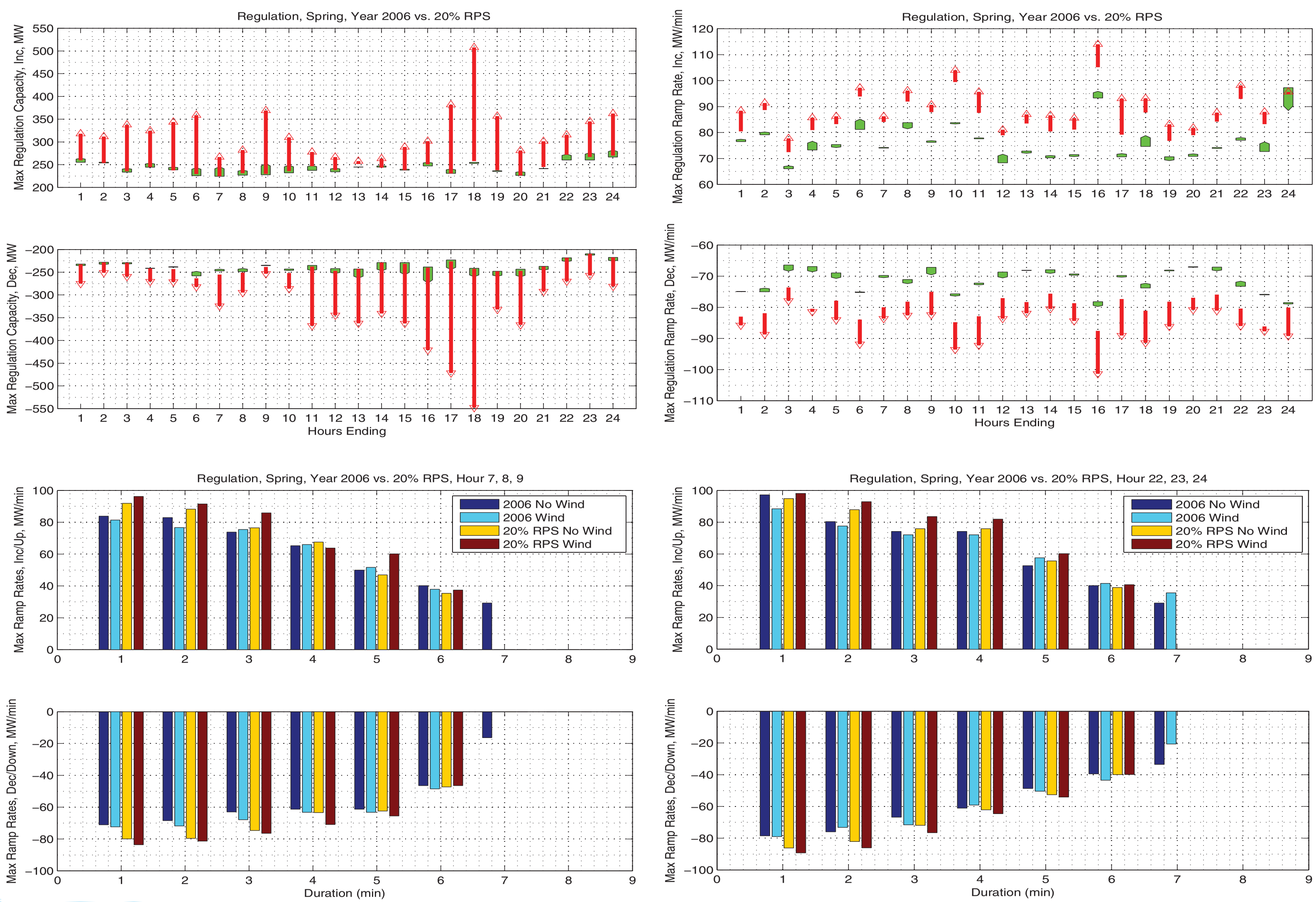






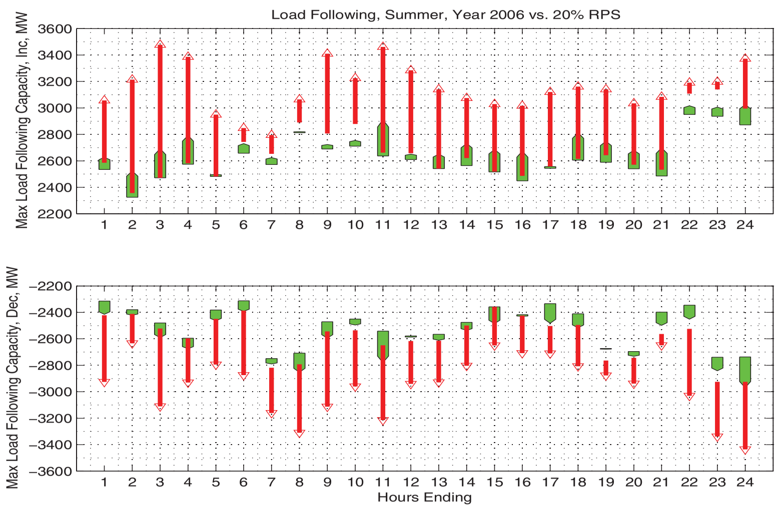
Spring: *Regulation Capacity, Ramp Rate and Ramp Duration*

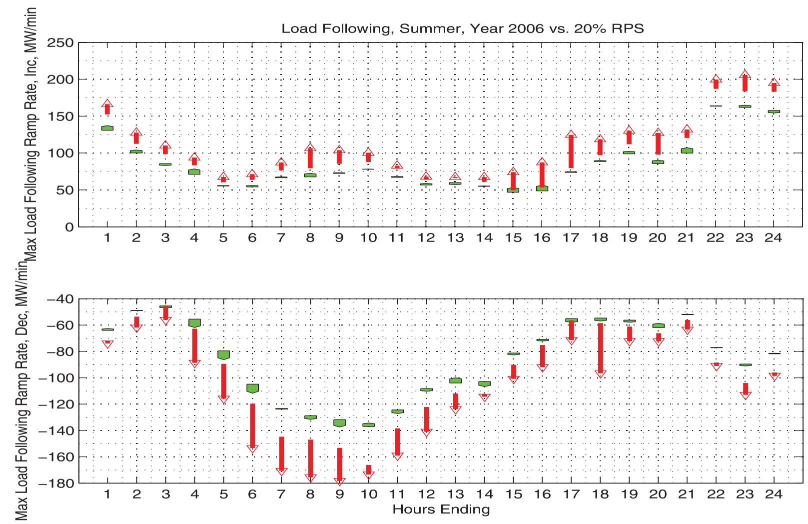
The green arrow represents 2006. The red arrow shows the expected 20% RPS increase due to wind only. The tail of the arrows corresponds to no wind.

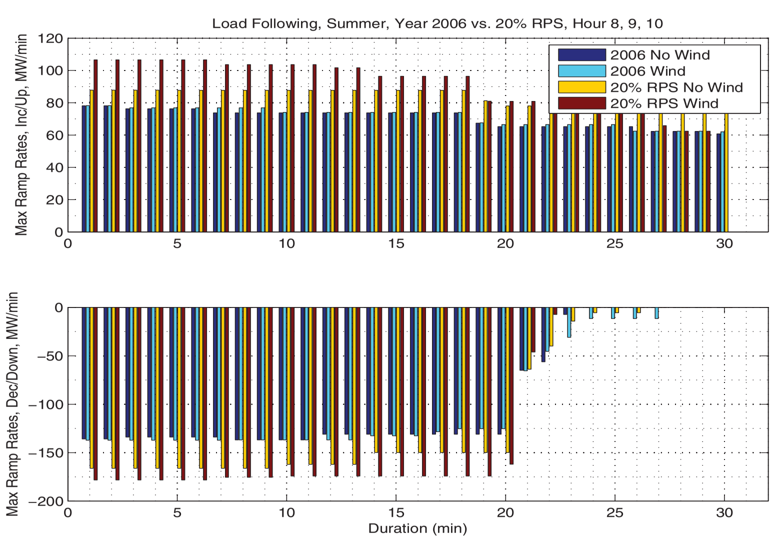


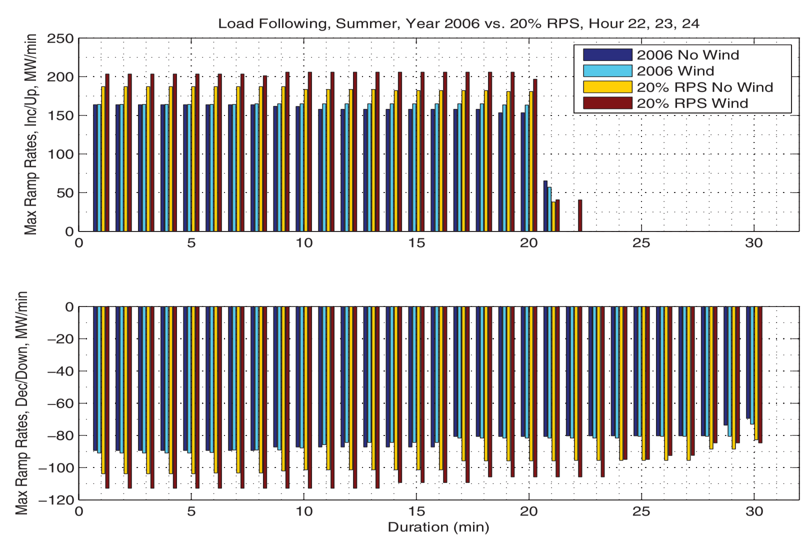
Summer: Load Following Capacity, Ramp Rate and Ramp Duration

The green arrow represents 2006. The red arrow shows the expected 20% RPS increase due to wind only. The tail of the arrows corresponds to no wind.



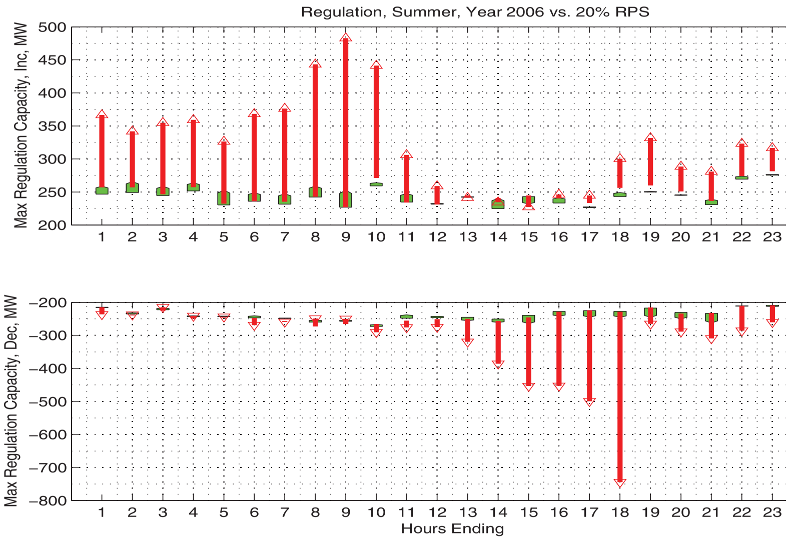


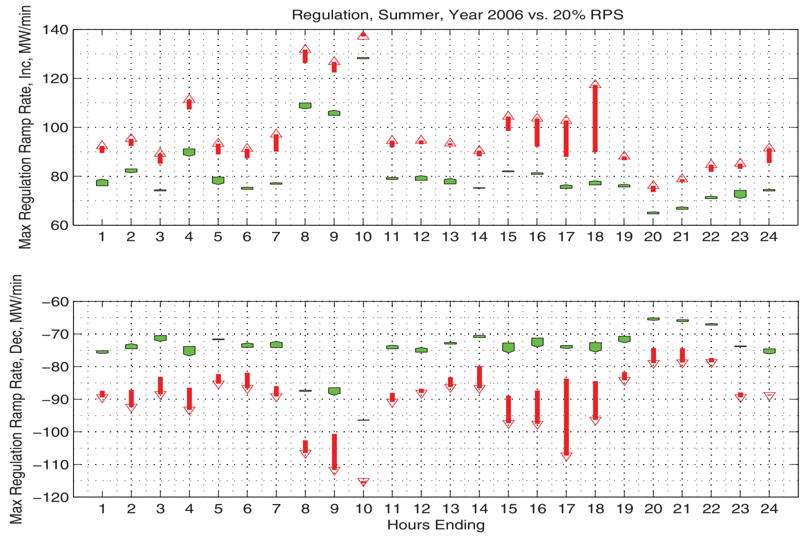


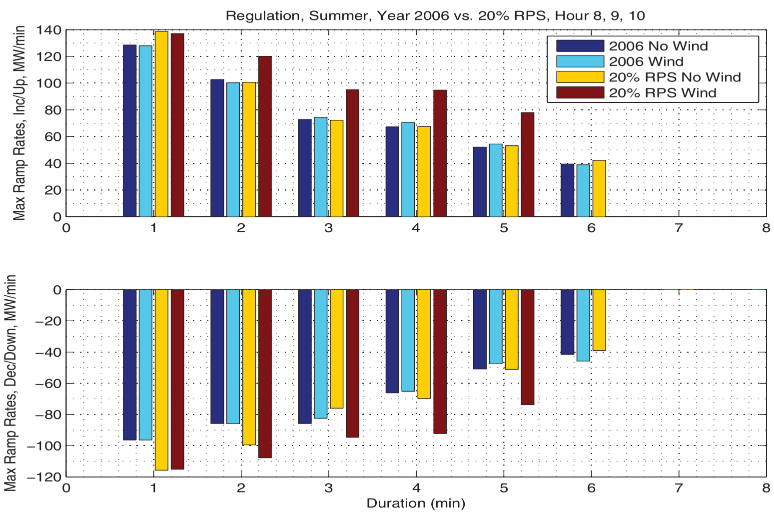


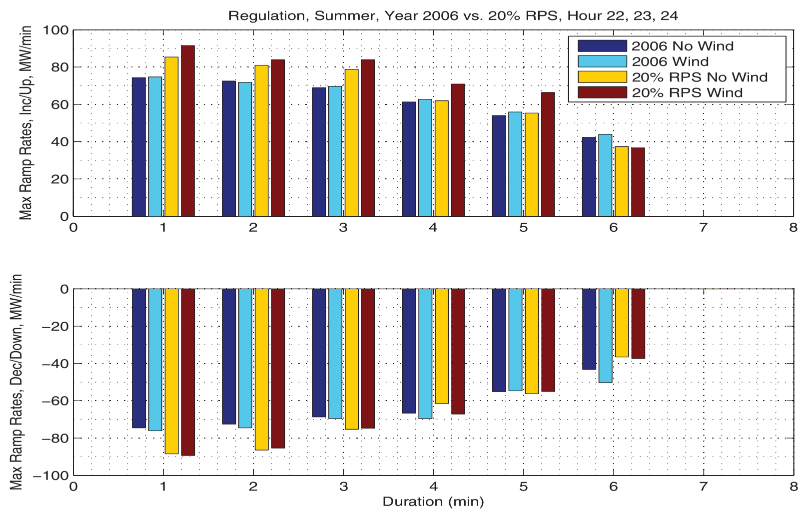
Summer: Regulation Capacity, Ramp Rate and Ramp Duration

The green arrow represents 2006. The red arrow shows the expected 20% RPS increase due to wind only. The tail of the arrows corresponds to no wind.



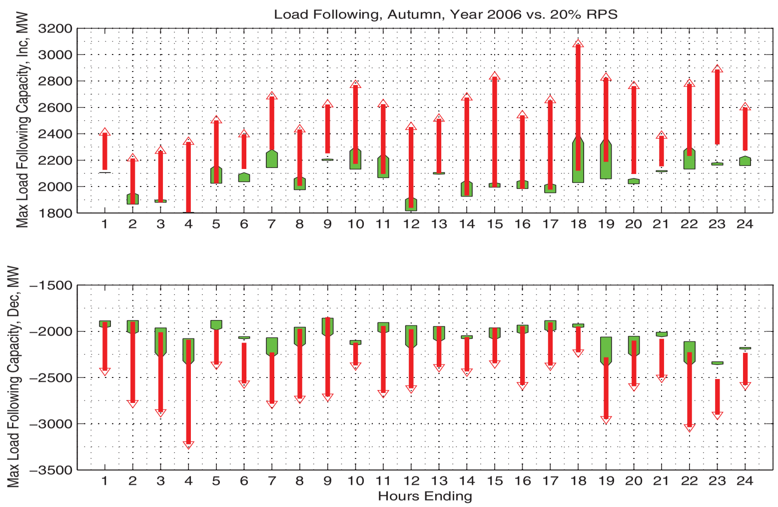


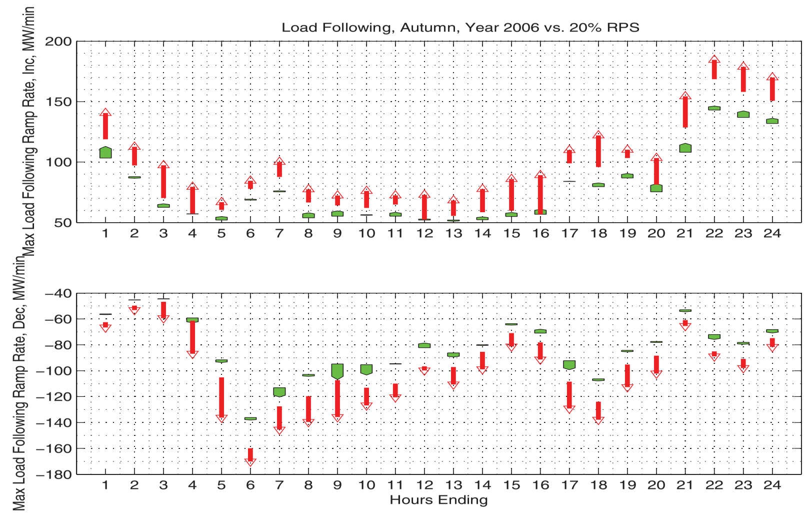


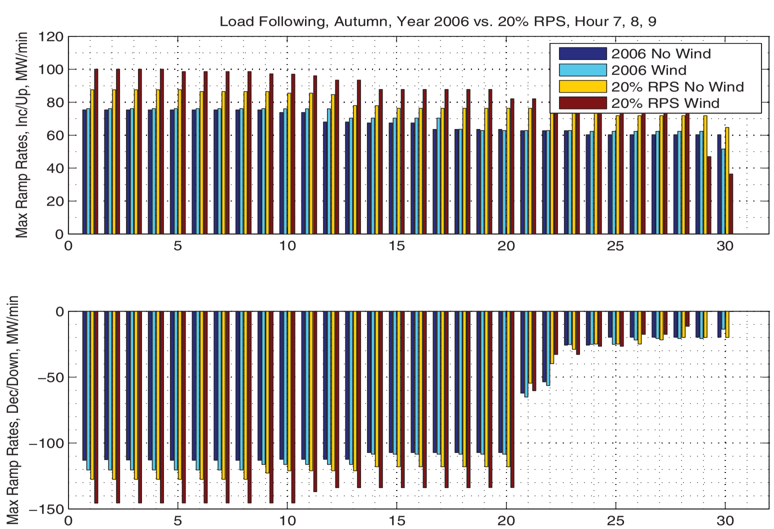


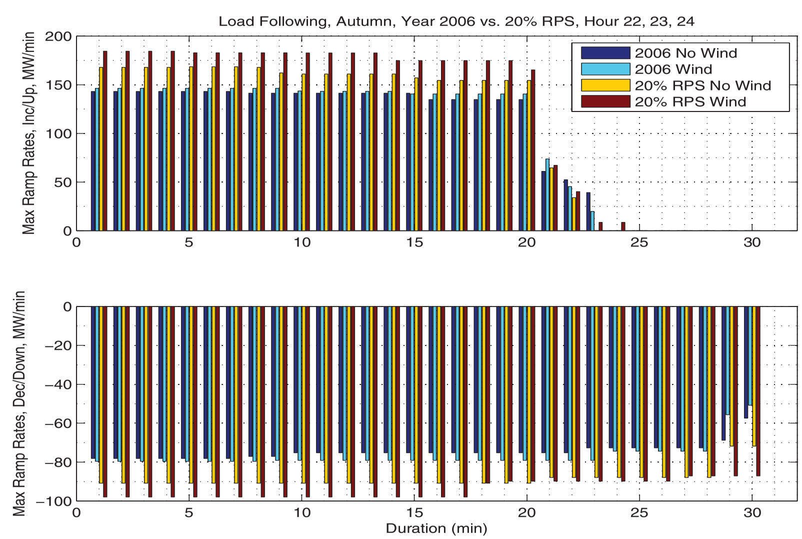
Fall: Load Following Capacity, Ramp Rate and Ramp Duration

The green arrow represents 2006. The red arrow shows the expected 20% RPS increase due to wind only. The tail of the arrows corresponds to no wind.



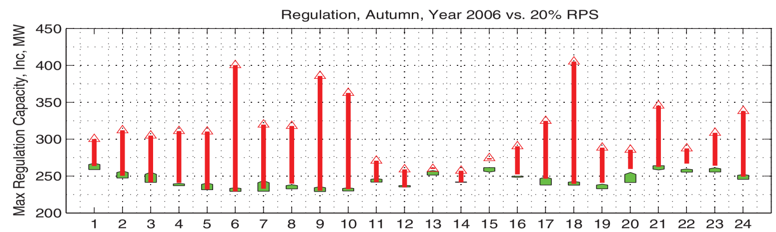


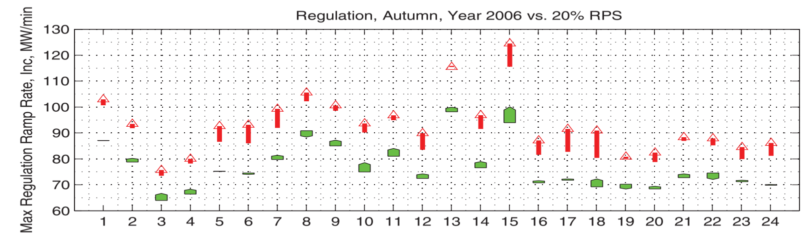


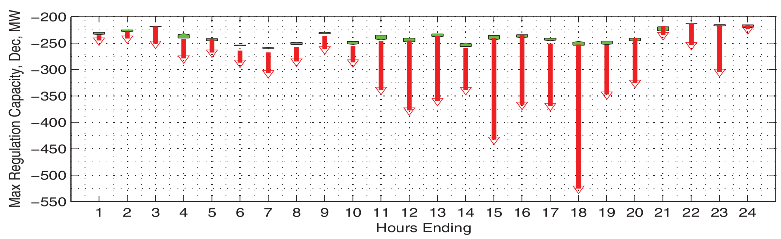


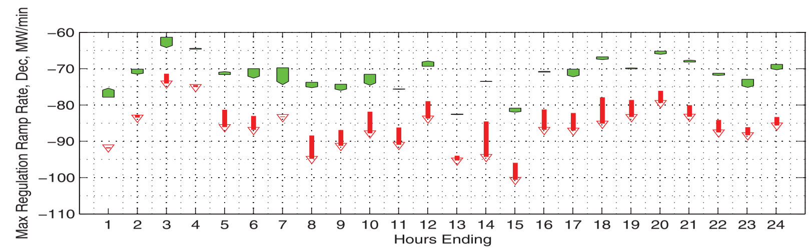
Fall: Regulation Capacity, Ramp Rate and Ramp Duration

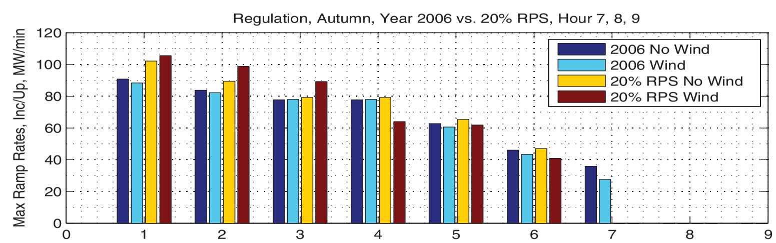
The green arrow represents 2006. The red arrow shows the expected 20% RPS increase due to wind only. The tail of the arrows corresponds to no wind.

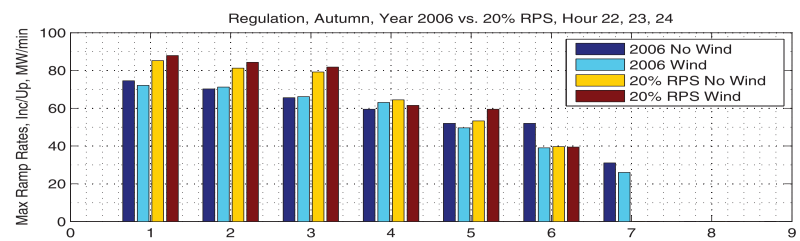


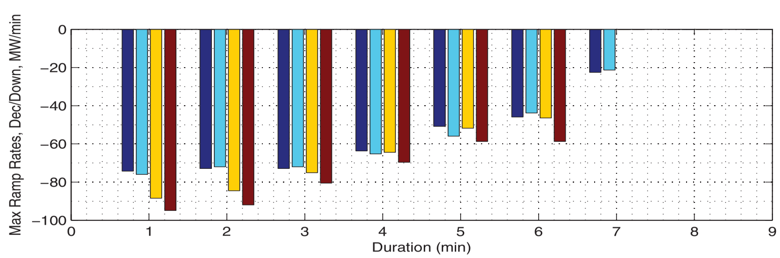


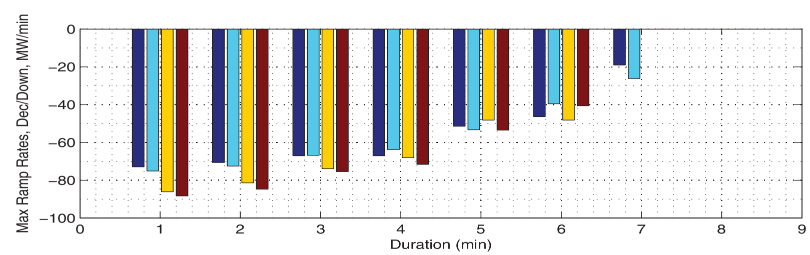












Winter: Load Following Capacity, Ramp Rate and Ramp Duration

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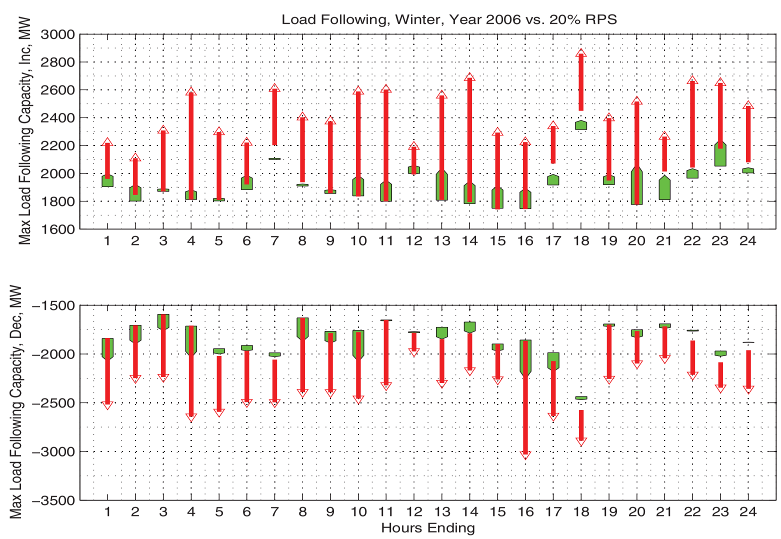
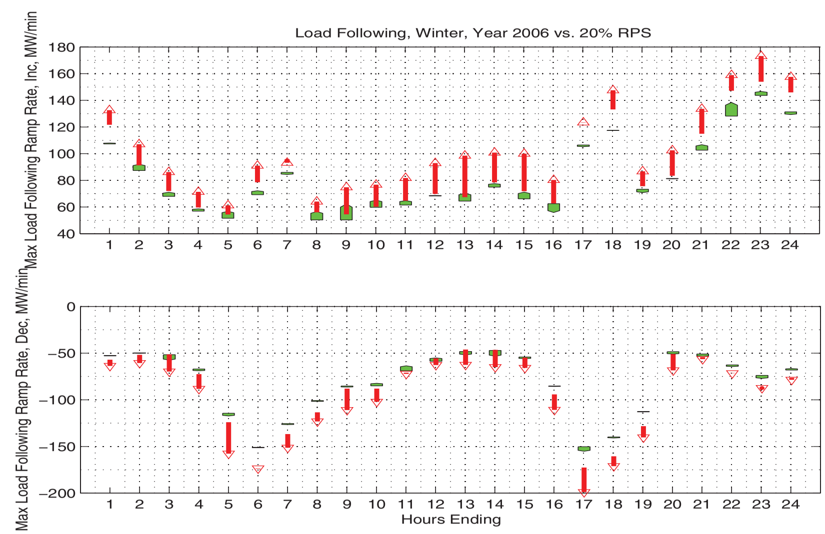
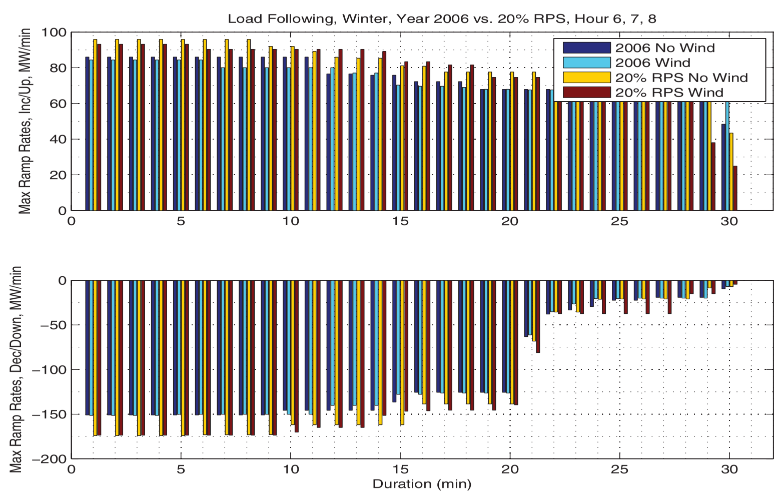
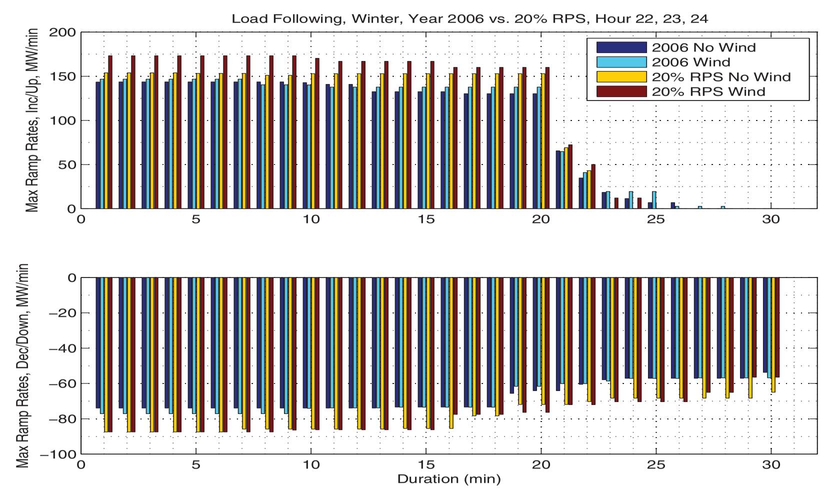


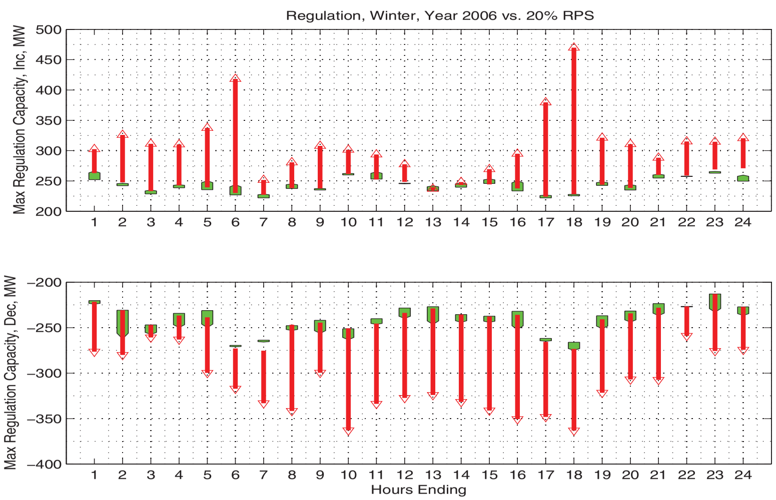


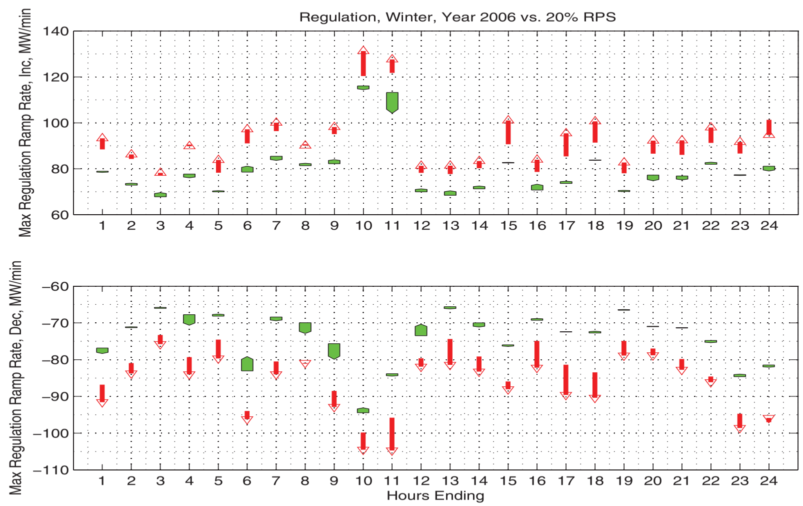


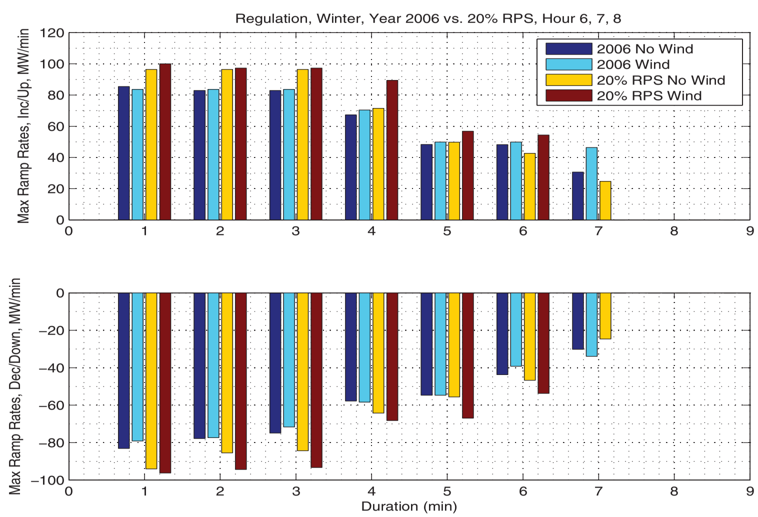


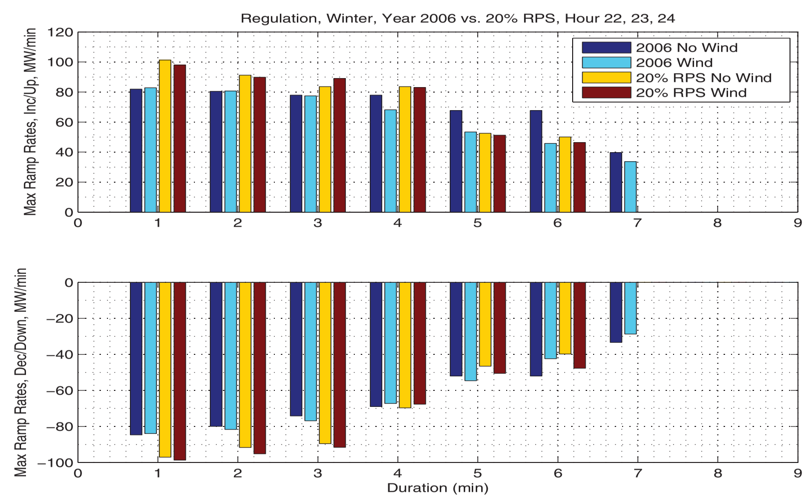
Winter: Regulation Capacity, Ramp Rate and Ramp Duration

The green arrow represents 2006. The red arrow shows the expected 20% RPS increase due to wind only. The tail of the arrows corresponds to no wind.









Appendix B — Study Methodology

Methodology to Evaluate the Impacts of Wind Generation on California ISO's Regulation and Load Following Requirements Under MRTU

Clyde Loutan (California ISO Project Lead), Phillip de Mello (California ISO/University of California, Davis), Yuri Makarov (Principal Consultant, Battelle), Jian Ma (Battelle/University of Queensland), Shuai Lu, (Battelle)

1. Assumptions

1.1. The impact of wind generation on the interconnection frequency is neglected.

1.2. Within the studied future periods, the hour-ahead hourly energy forecasts for all wind generation regions will be available at the California ISO.

1.3. The hour-ahead load and wind generation energy forecasts are provided at the latest 120 minutes before the actual beginning of an operating hour.

1.4. The real-time 5-minute load forecasts are provided 7.5 minutes before the actual beginning of a 5-minute dispatch interval (or 10 minutes before the middle point of this interval).

1.5. The load forecast errors are unbiased (i.e., they have a negligible average).

1.6. The load and wind forecast errors are random variables distributed according to the truncated normal distribution with certain autocorrelation between the subsequent forecast errors.

1.7. The MW load forecast error after the 20% RPS build out will have the same distribution as it had in 2006.

1.8. Within the studied future periods, the real-time wind generation forecasts (7.5 minutes before a 5-minute dispatch interval) will not be incorporated into the California ISO MRTU Real-Time Unit Commitment/Real-Time Dispatch systems.

1.9. Wind generation forecasts are not biased over a season.

1.10. Wind generation schedules are based solely on the corresponding hour-ahead wind generation forecasts that are assumed to be available for the California ISO/IOU scheduling process.

1.11. Pump storage is not considered as a part of the actual load and the load forecast. It is considered as a scheduled resource. The impact of small pumps that are not scheduled and are included into the actual load is neglected.

2. California ISO Scheduling and Real-Time Basics and Timelines

2.1. Generators' Schedules

Figure B-1 illustrates how the generators in the California ISO-controlled Grid are scheduled and dispatched.

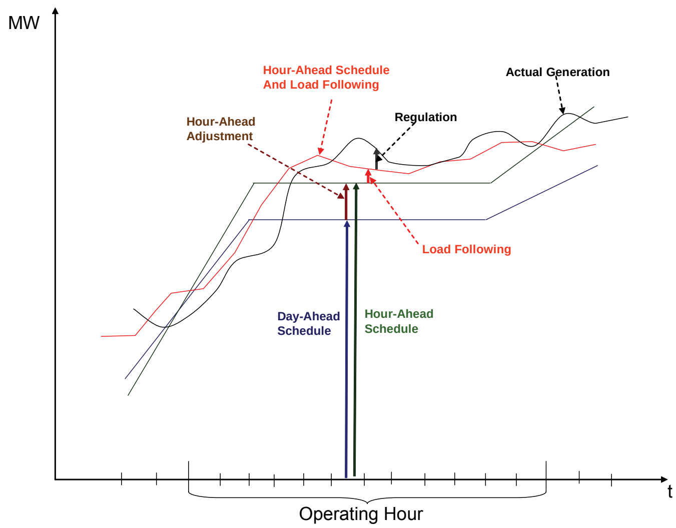


Figure B-1: California ISO-controllled Grid Scheduling Process

Hour-ahead schedules are block energy hourly schedules including the 20-minute ramps between the hours — Figure B-2. They are provided 75 minutes before the actual beginning of an operating hour. The load forecast used for the hour-ahead scheduling process is provided 2 hours before the beginning of an operating hour. The difference between the day-ahead and hour-ahead schedules constitute the required generation adjustment. California ISO facilitates the adjustment bids and the market.

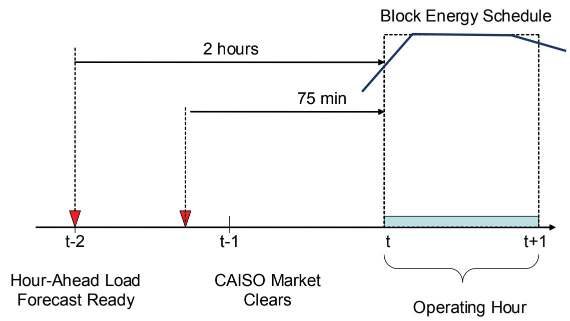


Figure B-2: California ISO Hour-Ahead Timeline

Load Following is an instructed deviation from schedule caused by the real-time (or supplemental) energy dispatch. The desired changes of generation are determined in real-time for each 5-minute dispatch interval 7.5 minutes before the actual beginning of the interval. System information used for that purpose (including real-time forecasts) is dated back approximately 7.5 minutes before the beginning of the interval.

2.2. Real-Time Dispatch and Regulation

The Real-Time Dispatch (also referred to as Load Following or Supplemental Energy Dispatch) is automatically conducted by the California ISO's MRTU applications using 15-minute intervals for Real-Time Unit Commitment and 5-minute intervals for Real-Time Economic Dispatch. The timeline for this process is shown in Figure B-3[1]

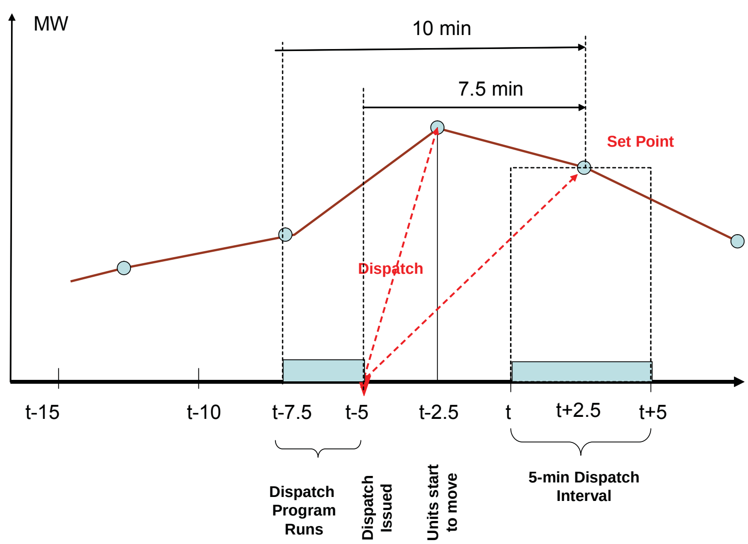


Figure B-3: California ISO Real-Time Dispatch Timeline

The desired changes of generation are determined in real-time for each 5-minute dispatch interval 5 minutes before the actual beginning of the interval. System information used for that purpose is dated back 7.5 minutes before the beginning of the interval. Units start to move toward the new set point 2.5 minutes before the interval begins. They are required to reach the set point in the middle of the interval (2.5 minutes after its beginning). The units may ramp by sequential segments, that is, the ramp is not necessarily constant.

The Very Short-Term Load Predictor (VSTLP) program provides an average load forecast for the interval [t, t+5] 7.5 minutes before the beginning of the interval or 10 minutes before the middle point of this interval. The VSTLP program uses EMS data to generate the forecast. This program also has an option to use the Automated Load Forecasting System (ALFS) output.

A similar timeline (forecast provided 7.5 minutes before the beginning of a 5-minute interval) can be adopted for the future wind generation forecast.

1 California ISO MRTU Training Document, Version 10.0.

2.3. Load Forecast Model

Refer to Appendix C for the methodology used to analyze load forecast errors.

2.4. Wind Generation Forecast Model

The hour-ahead wind generation forecast is assumed to be a part of the future California ISO/ IOU scheduling system.[2] Without such a forecast system, the California ISO load following requirements would become very significant after the 20% RPS build out. It is assumed that the wind generation forecast error is distributed according to the Truncated Normal Distribution (TND) law. Based on the assessment conducted by the AWS Truewind Company[3], the total 2-hours ahead wind energy forecast will have the following characteristics as shown in Table B-1.

Table B-1: Estimated Hour-Ahead Wind Generation Forecast Characteristics

	Average	Min	Max	Standard Deviation	Autocorrelation
Winter	0.00	-0.36	0.31	0.07	0.61
Spring	0.00	-0.43	0.31	0.09	0.71
Summer	0.00	-0.32	0.31	0.08	0.65
Fall	0.00	-0.32	0.40	0.08	0.59

3. Simulation of Future Scenarios and Data Set Generation

The study year is approximately 2013 with the full Tehachapi built out vs. the year 2006/2007.

3.1. Actual Load

For a future study year 2006+i, the annual actual load curve can be simulated as the year 2006 load multiplied by the i-th power of the annual load growth factor:

$$L_a^{2006+i} = (1+\gamma)^i \times L_a^{2006} \quad (3.1)$$

The actual 1-minute resolution load data is used for this study. The annual load growth factor is 1.5%.

3.2. Hour-Ahead Load Schedule Model

The scheduled load is the 1-hour (1hr) block energy schedule that includes 20-minute ramps between the hours. Please refer to Figure B-4.

2 The assumption is that all new wind generation additions in California will participate in the PIRP program, and therefore they will be provided with a centralized day-ahead and hour-ahead forecast service.

3 The estimated data was provided by AWS Truewind and processed by Phillip de Mello.

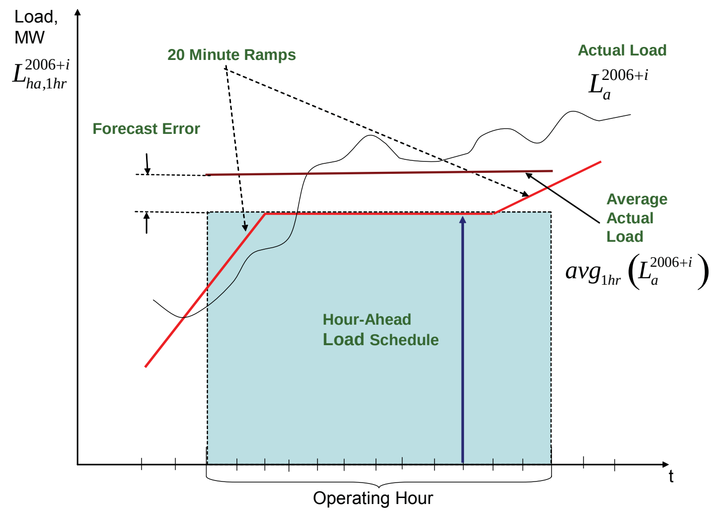


Figure B-4: CAISO Simulated Hour-Ahead Load Schedule (red line)

It can be calculated based on the load forecast error using the following approach:

The hour-ahead (ha) load schedule $L_{ha,1hr}^{2006+i}$ can be simulated based on the projected actual load (3.1) and the expected load forecast error $\varepsilon_{L,ha}$:

$$L_{ha,1hr}^{2006+i} = \Re_{20}\left\{avg_{1hr} L_a^{2006+i} - \varepsilon_{L,ha}\right\} \qquad (3.2)$$

Operator $\Re_{20}$ adds 20 minute ramps to the block energy load schedule.

The error can be simulated using a random number generator based on the statistical characteristics of the load forecast error (derived from 2006-2007 data).

The suggested probability distribution for the load forecast error is a doubly truncated normal distribution shown in Figure B-5. The truncated distribution helps to eliminate "tails" of the normal distribution, which would correspond to some unrealistically significant forecast errors.

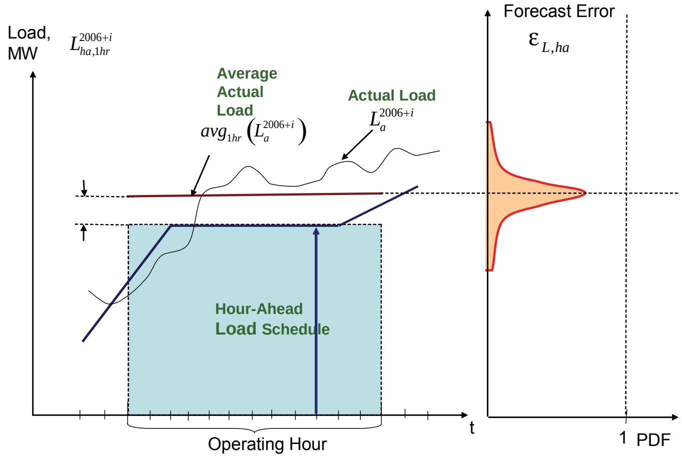


Figure B-5: Probability Density Function (PDF) of the Load Forecast Function (red line)

Based on these specified values, a random number generator will be used to generate values of $\varepsilon_{L,ha}$. For each operating hour, the random values of $\varepsilon_{L,ha}$ will be substituted into to produce the simulated hour-ahead load schedule. It is assumed that the load error distribution is *unbiased* for $PDF_N(\varepsilon)$, that is $\varepsilon_0 = 0$, and $\varepsilon_{L,ha}^{\min}$, $\varepsilon_{L,ha}^{\max}$ correspond to the minimum and maximum forecast errors specified for this study. These values are set to the following values ($L_{ha,1hr}^{2006+i}$ is the year (coinciding with the full build out) hour-ahead scheduled load, and L_a^{2006+i} is the actual load at the same hour).

$$L_{ha,1hr}^{2006+i} = \Re\left\{avg_{1hr} L_a^{2006+i} - \varepsilon_{L,ha}\right\}, \varepsilon_{L,ha}^{\min} \le \varepsilon_{L,ha} \le \varepsilon_{L,ha}^{\max} \quad (3.3)$$

$$\varepsilon_{L,ha}^{\max} = 3\sigma_{L,ha}$$

$$\varepsilon_{L,ha}^{\min} = -3\sigma_{L,ha}$$

3.3. Real-Time Load Forecast

The real-time load forecast is the average 5-minute load forecast that includes 5-minute ramps between the dispatch intervals. Please refer to Figure B-6.

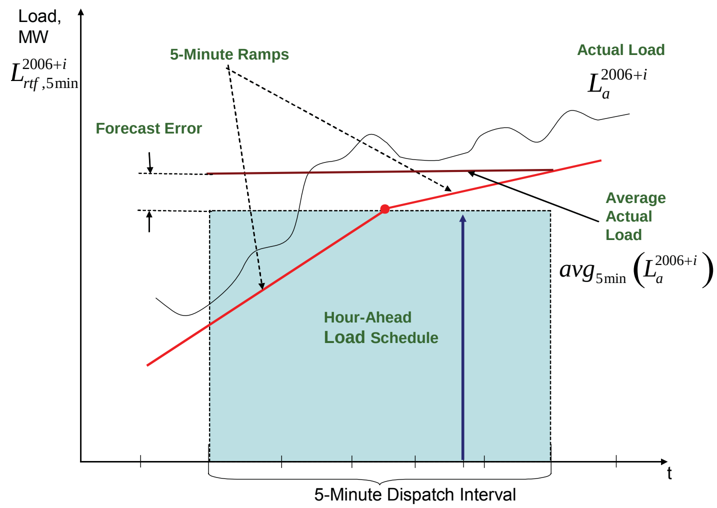


Figure B-6: California ISO Simulated Real-Time Load Forecast (red line)

It can be calculated based on the load forecast error using the following approach.

The real-time load forecast $L_{rtf,5\min}^{2006+i}$ can be simulated based on the projected actual load (3.1) and the expected load forecast error $\varepsilon_{L,rtf}$:

$$L_{rtf,5\min}^{2006+i} = \Re_5 \left\{ avg_{5\min} L_a^{2006+i} - \varepsilon_{L,rtf} \right\} \tag{3.4}$$

Operator $\Re_5$ adds 5-minute ramps to the block energy load schedule.

The error can be simulated using a random number generator based on the statistical characteristics of the real-time load forecast error (derived from 2006-2007 data). The suggested probability distribution for the real-time load forecast error is an unbiased doubly truncated normal distribution. The values of $\varepsilon_{L,rtf}^{\min}$ and $\varepsilon_{L,rtf}^{\max}$ are set to plus/minus $3\sigma_{L,rtf}$. The standard deviation of the hour-ahead load forecast error is $\sigma_{L,rtf}$.

Based on these specified values, a random number generator will be used to generate values of $\varepsilon_{L,rtf}$. For each operating hour, the random values of $\varepsilon_{L,rtf}$ will be substituted into (3.5) to produce the simulated real-time load forecast.

$$\begin{aligned} &L_{rtf,5\min}^{2006+i} = \Re \left\{ avg_{5\min} L_a^{2006+i} - \varepsilon_{L,rtf} \right\}, \varepsilon_{L,rtf}^{\min} \le \varepsilon_{L,rtf} \le \varepsilon_{L,rtf}^{\max} \\ &\varepsilon_{L,rtf}^{\max} = 3\sigma_{L,rtf} \\ &\varepsilon_{L,rtf}^{\min} = -3\sigma_{L,rtf} \end{aligned} \tag{3.5}$$

3.4. Actual Wind Generation Model

Refer to Appendix D for the methodology used to scale the expected wind generation to meet the 20% RPS build out time frame.

3.5. Wind Generation Hour-Ahead Scheduling Model

Wind generation hour-ahead schedules can be simulated using the wind generation model described in Appendix E and wind generation forecast error model described below. Similar to the load hour-ahead schedule and real-time load forecast models, the wind generation schedules and forecasts can be simulated for the hour-ahead scheduling and real-time dispatch time horizons as follow:

Wind generation schedule model $G_{ha,1hr}^{w}$ for the real-time scheduling process (hourly block energy forecast schedule) is as follows:

$$G_{ha,1hr}^{w,2006+i} = \Re_{20}\left\{avg_{1hr}\left(G_{a}^{w,2006+i}\right) - \varepsilon_{w,ha} \cdot CAP^{w,2006+i}\right\} \qquad (3.6)$$

The wind generation forecast error is expressed in % of the WG capacity $CAP^{w,2006+i}$.

Operator $\Re_{20}\{...\}$ adds 20-minute ramps between the hours; $\varepsilon_{w,ha}$ is the simulated hour-ahead wind generation forecast error. This error is generated with the help of *unbiased* TND random number generator. The TND has the following characteristics:

- Parameters $\varepsilon_{w,ha}^{\min}$, $\varepsilon_{w,ha}^{\max}$ correspond to the minimum and maximum total California ISO wind generation forecast errors specified for the TND. These values are set to plus/minus 3 standard deviation of the hour-ahead wind generation forecast error $\sigma_{w,ha}$.
- The standard deviation and autocorrelation of the hour-ahead wind generation forecast error $\sigma_{w,ha}$ is set to the seasonal values provided in Table B-1.

$$
\begin{aligned}
&G_{ha,1hr}^{w,2006+i} = avg_{1hr}G_a^{w,2006+i} - \varepsilon_{w,ha} \cdot CAP^{w,2006+i},\ \varepsilon_{w,ha}^{\min} \le \varepsilon_{w,ha} \le \varepsilon_{w,ha}^{\max} \\
&\varepsilon_{w,ha}^{\max} = \\
&\begin{cases} 3\sigma_{w,ha},\ if\ \left(avg_{1hr}G_a^{w,2006+i} - 3\sigma_{w,ha} \cdot CAP^{w,2006+i}\right) > 0, \\ avg_{1hr}G_a^{w,2006+i},\ if\ \left(avg_{1hr}G_a^{w,2006+i} - 3\sigma_{w,ha} \cdot CAP^{w,2006+i}\right) \le 0. \end{cases} \\
&\varepsilon_{w,ha}^{\min} = \\
&\begin{cases} -3\sigma_{w,ha},\ if\ \left(avg_{1hr}G_a^{w,2006+i} + 3\sigma_{w,ha} \cdot CAP^{w,2006+i}\right) < CAP^{w,2006+i}, \\ avg_{1hr}G_a^{w,2006+i} - CAP^{w,2006+i},\ if\ \left(avg_{1hr}G_a^{w,2006+i} + 3\sigma_{w,ha} \cdot CAP^{w,2006+i}\right) \ge CAP^{w,2006+i}. \end{cases}
\end{aligned} \tag{3.7}
$$

The truncation process is based on the following rules.

The real-time wind generation forecast is not provided or included in the real-time dispatch process. It is assumed that the naïve persistence model is implicitly used. Practically this means that for a 5-minute dispatch interval [t, t + 5], the implicit real-time wind generation forecast $G_{rtf,5\min}^{w,2006+i}$ is assumed to be equal to the actual wind generation at the moment t – 8:

$$
G_{rtf,5\min}^{w,2006+i}[t, t+5] = G_a^w[t-8] \tag{3.8}
$$

4. Assessment of Regulation and Load Following Impacts

NERC Operating Manual[4] considers regulation and load following requirements as parts of the operating reserve and gives the following definitions for these terms:

Regulation: The provision of generation and load response capability, including capacity, energy, and maneuverability, that responds to automatic controls issued by the Balancing Authority. The regulation reliability objective is to "follow minute-to-minute differences between resources and demand."

Load Following: The provision of generation and load response capability, including capacity, energy, and maneuverability, that is dispatched within a scheduling period by the Balancing Authority. The load following reliability objective is to "follow resource and demand imbalances occurring within a scheduling period."

4.1. Expressing Regulation and Load Following Requirements Using Simplified ACE Equation

The California ISO's control objective is to minimize its ACE to the extent sufficient to comply with the NERC Control Performance Standards. Therefore, the "ideal" regulation/load following signal

4 "NERC Operating Manual", June 15, 2006.

is the signal that opposes deviations of ACE from zero when it exceeds a certain threshold:

$$-ACE = -(I_a - I_s) + \underbrace{10B(F_a - F_s)}_{Neglected}$$
$$\approx G_s - L_s - G_a + L_a \to \min \qquad (4.1)$$

The generation component of the ACE equation can be represented as follows:

$$G_s = G_{ha} + G_{ha}^w,\ G_a = G_s + \Delta G^{lf} + \Delta G^r + \Delta G^w + \Delta G^{ud} \qquad (4.2)$$

where *ha* - denotes the hour-ahead generation schedule; lf - denotes instructed deviations from the hour-ahead schedule caused by generators involved in the load following process; r - denotes instructed deviations caused by generators involved in the regulation process; ΔG^{lf} and ΔG^r - is the deviation of the regulation and load following units from their base points; ΔG^w - is the deviation of the wind generators from their schedule (wind generation real-time schedule forecast error); and ΔG^{ud} is the total deviation of generators from the dispatched instructions. ΔG^{ud} will be simulated similarly to the load forecast error (random number generator based on TND).

The total deviation of generators from dispatch instructions,

$$\Delta G^{ud} = G_a - G_{ha} \qquad (4.3)$$

for the conventional units that are not involved in regulation and load following.

We will also introduce the following notations:

$$\Delta G^w = G_a^w - G_{ha}^w,$$
$$\Delta L = L_a - L_{ha} \qquad (4.4)$$

Since the control objective is ACE → 0, we can rewrite as

$$\Delta G^{lf} + \Delta G^r = \Delta L - \Delta G^w - \Delta G^{ud} \qquad (4.5)$$

where ΔL - is the deviation of the actual load from its real-time scheduled value (= load forecast error).

NOTE 1: Equation is written for instantaneous values of ΔL, ΔG^w and ΔG^{ud} Therefore, the statistical interaction between the load forecast error and the wind generation forecast error is fully preserved in.

NOTE 2: The load and wind generation errors can vary depending on the wind generation penetration level in the California ISO system and the accuracy of the load forecast compared to the accuracy of the wind generation forecast. Since the percent wind generation forecast error is more significant than the percent load forecast error, the former may have a considerable impact on $\Delta G^{lf} + \Delta G^{r}$.

4.2. "Would Be" Regulation Requirement Without Wind Generation

Wind generation would have no impact on regulation and load following requirements if

$$\Delta G^{w} = 0 \tag{4.6}$$

By substituting (4.6) into (4.5),

$$\Delta G^{rlf} = \Delta G^{lf} + \Delta G^{r} = \Delta L - \Delta G^{ud} \tag{4.7}$$

4.3. Regulation and Load Following Assessment

This procedure can be used to separate regulation from load following based on short-term forecasts of the system total load and total wind generation.

The schedule/forecast based approach uses the short-term forecasts of wind generation and load, $G^{w,y}_{rtf,5\min}$ and $L^{y}_{rtf,5\min}$. In this case, the following formulas can be used:

$$\begin{aligned} \Delta G^{r}(m) &= L^{y}_{a}(m) - G^{w,y}_{a}(m) - L^{y}_{rtf,5\min}(m) + G^{w,y}_{rtf,5\min}(m), \\ \Delta G^{lf}(m) &= L^{y}_{rtf,5\min}(m) - G^{w,y}_{rtf,5\min}(m) - L^{y}_{ha,1hr}(m) + G^{w,y}_{ha,1hr}(m) \end{aligned} \tag{4.8}$$

Figure B-7 illustrates the idea of separating regulation from load following based on short-term forecasts.

Load Following is understood as the difference between the hourly energy schedule including 20-minute ramps[5] (shown as the red line) and the short-term 5-minute forecast/schedule and applied "limited ramping capability" function (blue line). This difference is also shown as the green area below the curves.

Regulation is interpreted as the difference between the actual California ISO generation requirement and the short-term 5-minute forecast/schedule and applied "limited ramping capability" function (green and blue lines correspondingly). In Figure B-7 it is also shown separately as the tan area.

5 IMPORTANT NOTE: The actual California ISO real-time dispatch process is based on the actual generation, but not the real-time schedules (Source: Tong Wu, June 7, 2007). The scheduled generation used in the proposed procedure is based on the Assumptions, Section 1.

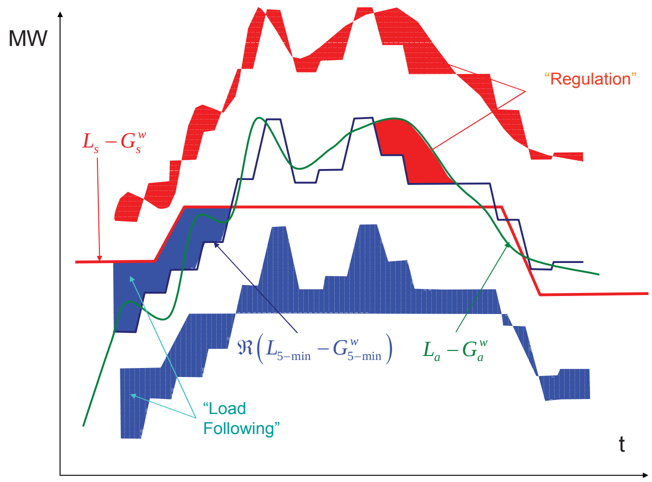


Figure B-7: Separation of Regulation from Load Following Based on Simulated Hour-Ahead Schedule

5. Assessment of Ramping Requirements

The regulating unit ramping capability can directly influence the required regulation and load following capacity. If the ramping capability is insufficient, more units and more capacity must be involved in regulation to follow the ramps. That is why the additional ramping requirements caused by wind generation should be studied and quantified.

The required ramping capability can be derived from the shape of the regulation/load following curve ΔG^{rlf}. This derivation needs to be done in a scientific way. We propose to use the "swinging door"[6] algorithm for this purpose. This is a proven technical solution implemented in the PI Historian and widely used to compress and store time dependent datasets.

Figure B-8 demonstrates the idea of the "swinging door" approach. A point is classified as a "turning point" whenever — for the next point in the sequence — any intermediate point falls out of the admissible accuracy range $\pm\varepsilon_{\Delta G}$. For instance, for point 3, one can see that point 2 stays inside the window abcd. For point 4, both points 2 and 3 stay within the window *abef*. But for point 5, point 4 goes beyond the door, and therefore point 4 is marked as a turning point.

6 D.C. Barr, "The Use of a Data Historian to Extend Plant Life", Life management of power plants, 12-14 December 1994, Conference Publication No. 401.0 IEE 1994.

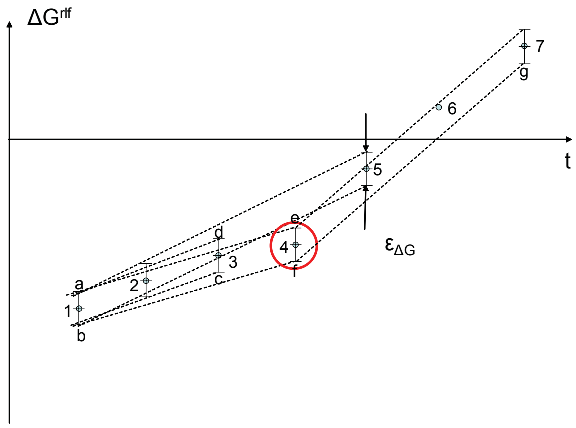


Figure B-8: "Swinging Door" Algorithm - Concept

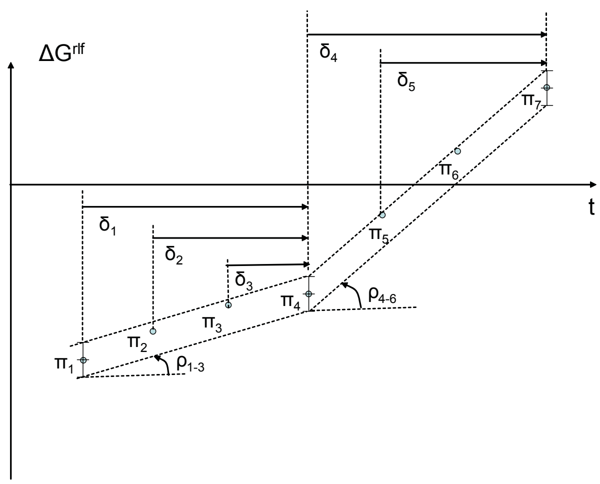


Figure B-9: "Swinging Door" Algorithm – Obtaining Regulation, Ramps and Their Duration

Based on this analysis, we conclude that points 1, 2 and 3 correspond to the different magnitudes of the regulation signal, π_1, π_2 and π_3, whereas the ramping requirement at all these points is the same, ρ_{1-3}. The swinging door algorithm also helps to determine the ramp duration δ.

6. Concurrent Statistical Analysis of the Regulation and Load Following Requirements

As discussed previously, the regulation capacity and ramping requirements are inherently related. Insufficient ramping capability could cause additional capacity requirements.

In this document, we propose a concurrent consideration of the regulation and load following capacity, ramping and ramp duration requirements.

For the regulation/load following requirement curve ΔG^{rlf} , we can apply the "swinging door" algorithm and determine the sequences of its magnitudes and ramps, $\pi_1, \pi_2, \ldots$, $\rho_1, \rho_2, \ldots$, and $\delta_1, \delta_2, \ldots$. The triads $(\pi_i, \rho_i, \delta_i)$ can be used to populate the three-dimensional space of these parameters – see Figure B-10.

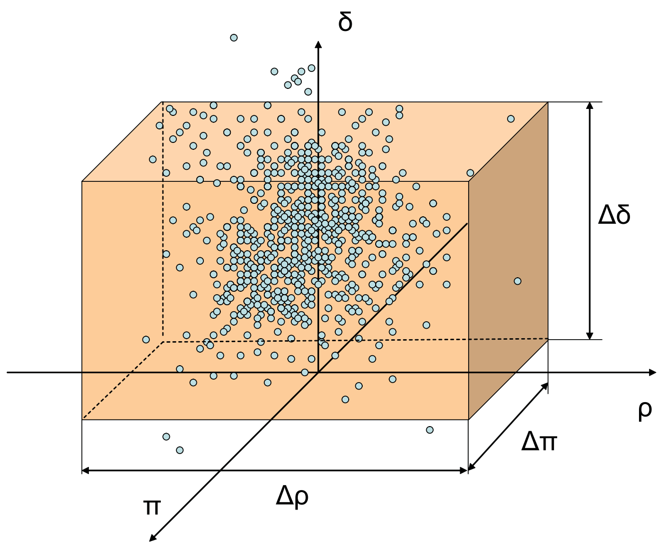


Figure B-10: Concurrent Consideration of the Capacity, Ramping and Duration Requirements

For given ranges of these three parameters, $\Delta\pi, \Delta\rho$ and $\Delta\delta$, a box can be plotted in this space, so that some triads are inside the box (N_{in}), and some are outside (N_{out}). This approach helps to determine the probability of being outside the box

$$p_{out} = \frac{N_{out}}{N_{out} + N_{in}}$$

If a point lays outside the box, the regulation/load following requirements are not met at this point. We will require that this probability must be below certain minimum probability, P_{min}. The task is to find the position of the wall of the probability box that corresponds to a given P_{min}.

Appendix C — Load Forecast Error Analysis

1. Load Forecast

The California ISO forecast demand is calculated by the Automated Load Forecasting System (ALFS). ALFS calculates the California ISO forecast demand for several different time frames. The day-ahead forecast is calculated approximately 14 hours before the operating day, while the hour-ahead forecast is calculated about two hours prior to the operating hour, and subsequent half-hour forecasts are calculated for the remainder of the operating day. This process is repeated before each operating hour and each subsequent half-hour forecast is modified. Each of the half-hour forecasts for the remainder of the operating day is used by the Security Constrained Unit Commitment program so that short start units could be committed if it's anticipated that resources would be deficient.

In the California ISO's Real-Time Market Systems, another forecasting tool called the Very Short-Term Load Predictor (VSTLP) utilizes the latest ALFS half-hour forecast and the most recent generation output from the State Estimator to forecast a 15-minute demand forecast, which is used by the Real-Time Unit Commitment (RTUC) and a 5-minute forecast which is used by Real-Time Economic Dispatch. Under MRTU, all forecast demand would include transmission losses, but would exclude pump loads.

1.1. Load Forecast Error

In order to assess the expected forecast error to meet the 20% RPS goal, it was decided to ascertain the actual forecast errors observed in 2006. For this study, the seasonal forecast errors for 2006 are assumed to be the same as after the build out, although some may argue that forecast errors would be higher at higher load levels. The reason for assuming the forecast errors would be about the same as they are now is the expectation that forecast errors would be reduced with improved forecasting techniques and additional weather information.

The forecast demand errors were characterized for three time frames, the hour-ahead, half-hour and 5-minute forecasts. For each time frame, the forecast error was determined by taking the difference between the forecast demand for that time frame and the actual average demand for the corresponding period. The maximum, minimum, average and standard deviation were calculated on the error for each time frame. The probabilities of error magnitudes were then calculated by comparing the number of occurrences in error magnitude ranges to the total number of occurrences. The probability density function can be approximated using a truncated normal distribution that is defined by using the mean and standard deviation for the forecast error for the different seasons. Refer to Figure C-1.

The truncated normal distribution is very similar to a normal distribution, but differs in that its extremities are bounded or truncated. The truncated normal distribution is more practical for load forecasting data because it is not expected that the forecast error would exceed certain limits. The formula for the truncated normal distribution used in this study is given below:

$$PDF_{TND}(\varepsilon) = \begin{cases} 0, & -\infty \le \varepsilon < \varepsilon_{\min} \\ \dfrac{PDF_N(\varepsilon)}{\int_{\varepsilon_{\min}}^{\varepsilon_{\max}} PDF_N(\varepsilon)\,d\varepsilon}, & \varepsilon_{\min} \le \varepsilon \le \varepsilon_{\max} \\ 0, & \varepsilon_{\max} \le \varepsilon \le +\infty \end{cases}$$

$$PDF_N(\varepsilon) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-\frac{1}{2}\left(\frac{\varepsilon - \varepsilon_0}{\sigma}\right)^2}, \quad -\infty \le \varepsilon \le +\infty$$

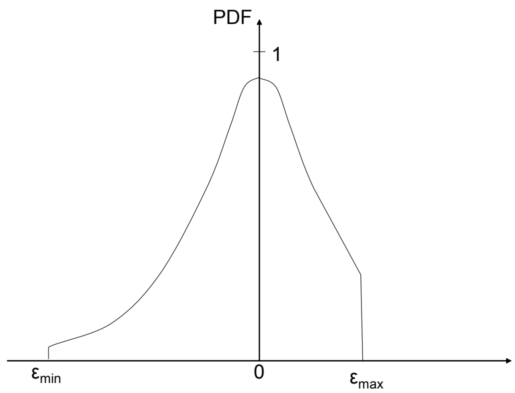


Figure C-1: Unbiased Truncated Normal Distribution

Additionally, the autocorrelation coefficient (*R*) was calculated to see if the forecast errors are time dependent (i.e., is the forecast load typically under-forecast or over-forecast for certain time periods?). The autocorrelation depends on the number of observations, the standard deviation of the observations, the sample mean and the current and next observation. Autocorrelation has values between -1 and 1. A value of 1 indicates that the next value has a very strong positive dependence on the previous value, while a value of -1 indicates that the next value has a strong negative dependence on the previous value. An autocorrelation value of 0 indicates that the current value gives no indication of what the next value will be.

$$R = \frac{1}{(n-1)\sigma^2} \sum_{i=1}^{n-1} (X_i - \mu)(X_{i+1} - \mu)$$

Where: n is the number of occurrences
X is the value of the error at that time
μ is the average value of the error
σ is the standard deviation of the error

2. Hour-Ahead Forecast

Currently, and prior to MRTU implementation, the hour-ahead forecast error is simply the difference between the hour-ahead forecast and the average hourly actual demand (including pump loads) for a particular operating hour. For 2006, the hour-ahead forecast was found to have a mean absolute error (MAE) of 2% of actual load.

$$MAE = \frac{1}{N}\sum\frac{|Actual - Forecast|}{Actual}\times 100$$

The raw forecast error data was filtered through a two-step process to remove bad data points: 1) errors in excess of 50% of actual load were removed, and 2) errors greater than 3 standard deviations from the mean were removed if there were data errors or problems on the grid.

Table C-1 summarizes the minimum, maximum, average, standard deviation and autocorrelation of the hour-ahead load forecast errors for the different seasons.

Table C-1: Summary of Hour-Ahead-Load Forecast Error (Actual Load – Forecast Load)

Season	Average (MW)	Min (MW)	Max (MW)	Standard Deviation (MW)	Autocorrelation
Winter	-35.2	-3,849	1,519	652	0.69
Spring	-24.1	-2,101	1,931	601	0.73
Summer	-130.4	-3,771	2,446	900	0.89
Fall	-69.2	-2,628	2,081	687	0.83

Figure C-2a, C-2b, C-2c & C-2d show the seasonal comparisons of the theoretical load error distribution (red line) to actual load error distributions (blue bars). During the spring, fall and winter months, the forecast errors typically mimic a truncated normal distribution function. As shown in Figure C-2b, during the 2006 summer months, the load forecast error was typically on the high side or was greater than 800 MW for approximately 23% of the time. Much of this high forecast was due to the number of days the average temperature exceeded 100 degrees F within the California ISO-controlled Grid.

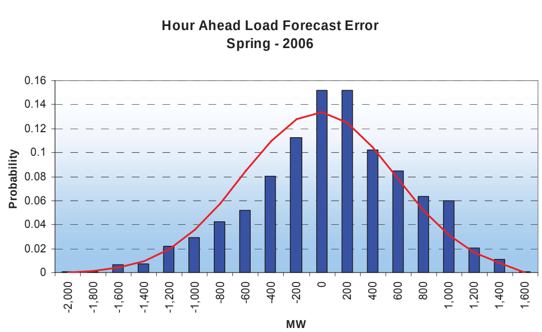


Figure C-2a: Spring Load Forecast Error

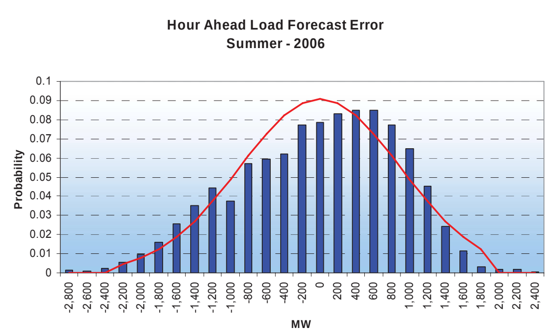


Figure C-2b: Summer Load Forecast Error

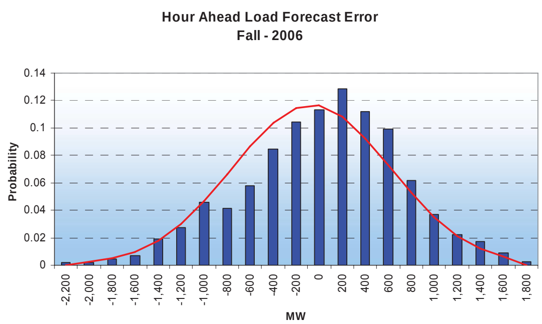


Figure C-2c: Fall Load Forecast Error

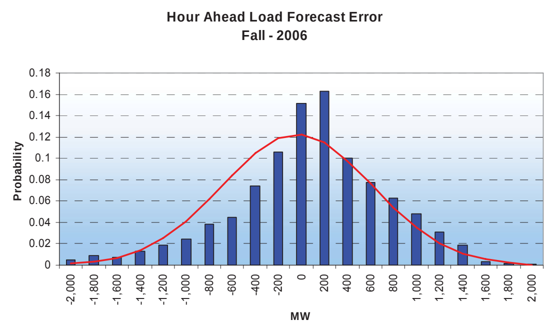


Figure C-2d: Winter Load Forecast Error

3. Half-Hour Forecast

The half-hour forecasts are similar to the hour-ahead forecasts except they provide a more granular view of the operating hour in question. Once again, the load data was extracted from the PI database, with the difference that it is half-hour averages rather than hourly averages. The time period used was January through June of 2007. Half-hour forecast errors were not evaluated by season because of missing data. Additionally, the half-hour load forecast does not include pumping load, so pump loads were removed from the actual half-hour load data for the comparison. The mean absolute error for the half-hour forecast was found to be 0.77%. Table C-2 below shows the minimum, maximum, average, standard deviation and autocorrelation of the half-hour forecast error.

Table C-2: Summary of Half-Hour Load Forecast Error

Average (MW)	Min (MW)	Max (MW)	Standard Deviation (MW)	Autocorrelation
-8.90	-1370	1520	258	0.89

As shown in Figure C-3, the half-hour load forecast error is significantly smaller than the hour-ahead forecast error. For the first half of 2007, the forecast error was greater than 500 MW approximately 5% of the time.

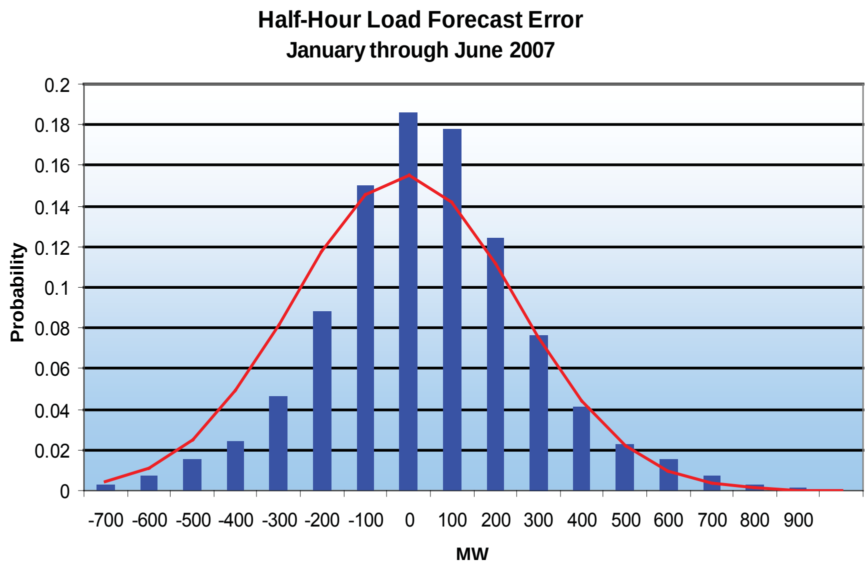


Figure C-3: Comparison of Half-Hour Load Forecast Error with Theoretical Distribution

4. 5-Minute Forecast (real-time forecast)

The 5-minute load forecast is calculated by the California ISO's VSTLP application, which is based on neural network training. It uses 5-minute averages of actual load data (including pump load) generated from the State Estimator for the last 13 months as input. The VSTLP produces a load forecast for each 5-minute dispatch interval in the Real-Time Market time horizon. This 5-minute forecast is run about 10-minutes before the operating interval and consists of a block of power for that time. Variation within that 5-minute interval is made up with regulation. The 5-minute load data and the 5-minute load forecasts were extracted from the SI UP database. The mean absolute error of the 5-minute load forecast is 0.29%. Table C-3 below shows the minimum, maximum, average, standard deviation and autocorrelation of the 5-minute forecast error.

Table C-3: Summary of 5-Minute Load Forecast Error

Average (MW)	Min (MW)	Max (MW)	Standard Deviation (MW)	Autocorrelation
1.15	-349	349	98	0.61

Figure C-4 shows the 5-minute load forecast error for one month of data (mid-March through mid-April) is less than 100 MW for almost 85% of the time.

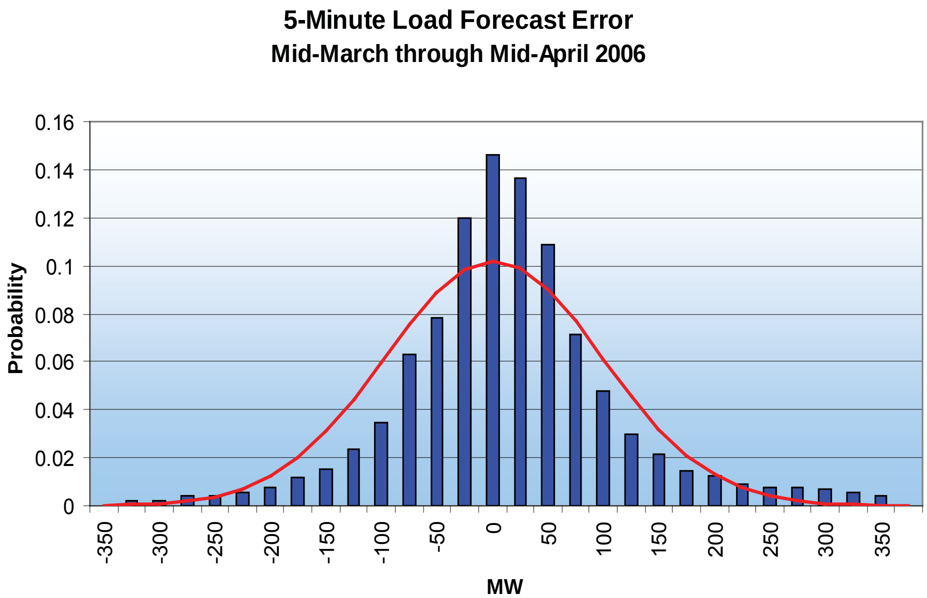


Figure C-4: Comparison of 5-Minute Load Forecast Error and Theoretical Error Distribution

Appendix D — Wind Generation Forecast for the 20% RPS

1. Scaling Wind for the 20% RPS

Creating a realistic wind forecast dataset is one of the most important steps in analyzing the wind variability to meet the 20% RPS. Simply scaling the 2006 actual wind production by the ratio of the expected capacity to the current capacity fails to take into account any local weather variation within a resource area. This methodology would also neglect any benefits of aggregation, which will reduce overall variability. The following approach describes the methodology used to create a reasonable dataset of future wind generation based on the realized 2006 wind production, which remedies some of the problems with direct scaling.

The 20% RPS energy production and minute-to-minute variability were calculated separately. The reason for calculating the expected production separately stems from the fact that wind energy production and variability during short time intervals are often driven by separate phenomenon. For the analysis and based on the California ISO's generation interconnection queue, three new wind parks totaling 3,540 MW were assumed to be located in the Tehachapi area and a new 500 MW wind park located in the Solano area. The other existing wind parks were assumed to remain the same as 2006.

2. Energy Production

The 20% RPS hourly energy production data for the Tehachapi and Solano regions were provided by AWS Truewind. The data is the same as that used in the CEC IAP study, except that it omits facilities that are not likely to be constructed by the 2013 timeframe, which is when the 20% RPS build out is scheduled to be completed. AWS Truewind generated the expected wind production data using actual production data from January 2002 through December 2004 combined with their atmospheric simulation models to create wind speeds for the resource areas. AWS Truewind then extracted production values based on the resource area conditions with local corrections for each site and the expected power curve.[7] The AWS Truewind initial dataset is composed of hourly block energy forecasts for each of the existing and expected wind parks in the Tehachapi and Solano areas as shown in Figure D-1. As shown in Figure D-2, 20-minute linear inter-hour ramps were added to this original dataset to smooth the overall shape, and to prevent changes between hours from introducing artificial variation. Figure D-1 shows sample energy production data with the inter-hour ramps added.

7 "Intermittency Analysis Project: Characterizing New Wind Resources in California" PIER Interim Project Report. California Energy Commission. CEC-500-2007-014. February 2007.

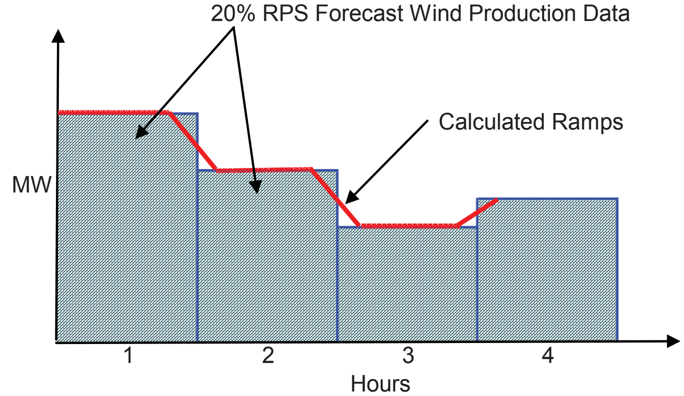


Figure D-1: Expected Wind Energy Production With Linear Ramps

3. Minute-to-Minute Variability

The minute-to-minute variability is the actual minute-to-minute variation observed from the existing wind production in the various resource areas for 2006. The minute-to-minute variations are defined as the 1-minute deviation from a 60-minute centered moving average. Using a centered moving average takes out the longer term trends in the wind production (i.e., ramping up in the evening or down in the morning). A 60-minute average was used to closely match the energy given as hourly blocks. Figure D-2 shows a sample of wind production and a comparison between the hourly average and the moving average. Since the 20% RPS energy production values are not based on the 2006 wind production data, it can at times have opposite inter-hour trends. These opposite trends could exacerbate the variability if it were taken from fixed hourly averages of 2006 data and then combined directly onto the expected production. Figure D-3 shows how the inter-hour trends in energy can be different between the two datasets.

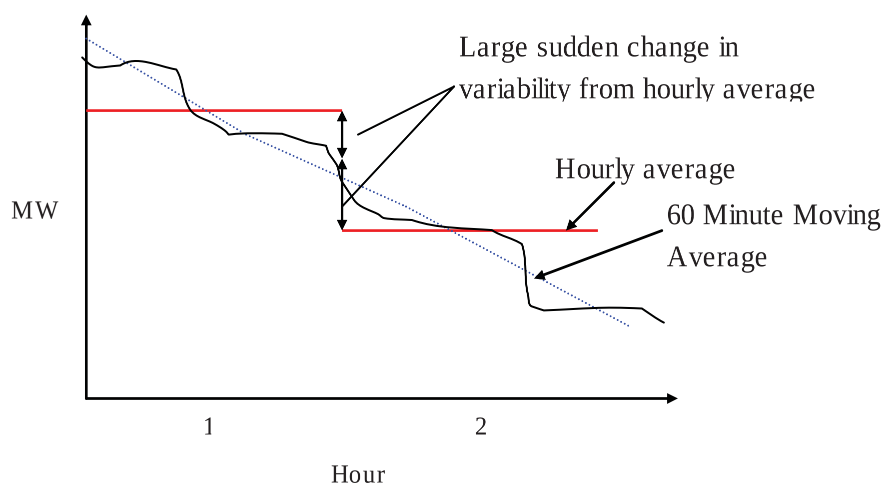


Figure D-2: Sample Wind Production with Hourly Average and Moving Average

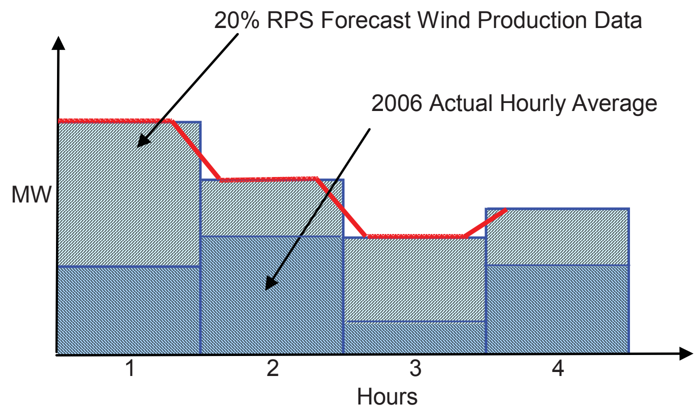


Figure D-3: Possible Average Wind Generation Pattern

The variability was then scaled up assuming that new wind farms would have similar levels of variability and that short-term variations would be completely uncorrelated.

Figure D-4 shows the correlation coefficient of short-term fluctuations of Solano and Tehachapi wind parks, and shows there is no significant correlation. Figure D-5 shows the correlation coefficient of short-term fluctuations of the two wind parks in Tehachapi. The correlation coefficient is a measure of the extent that two variables are changing together. It is bounded between 1 and -1. If it has a value of 1, the two variables always change together in the same direction, if it has a value of -1, they change in opposite directions. If the correlation coefficient is 0, the two variables vary completely independently of each other. The equation for the correlation coefficient is shown below.

$$Correlation = \frac{\sum_{1}^{N}(X-\mu_X)(Y-\mu_Y)}{(N-1)\sigma_X\sigma_Y}$$

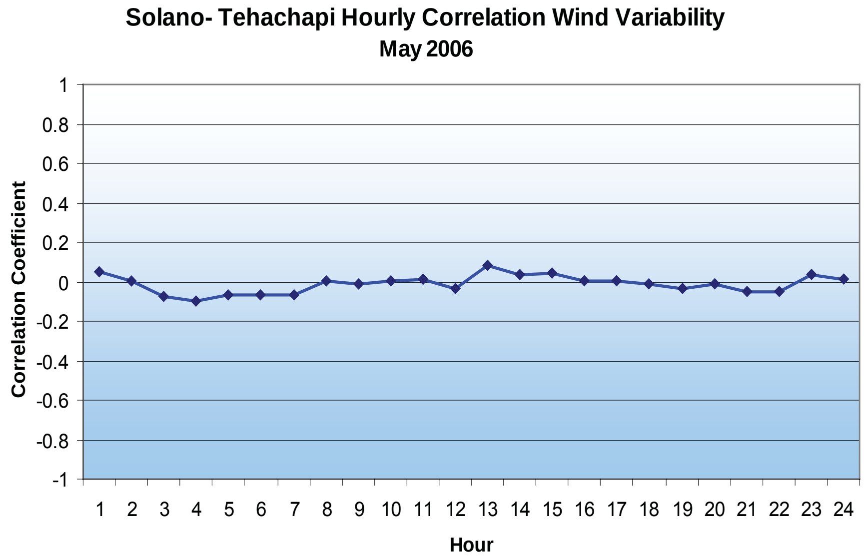


Figure D-4: Correlation of Short-Term Variations of Two Wind Parks in Tehachapi Resource Area

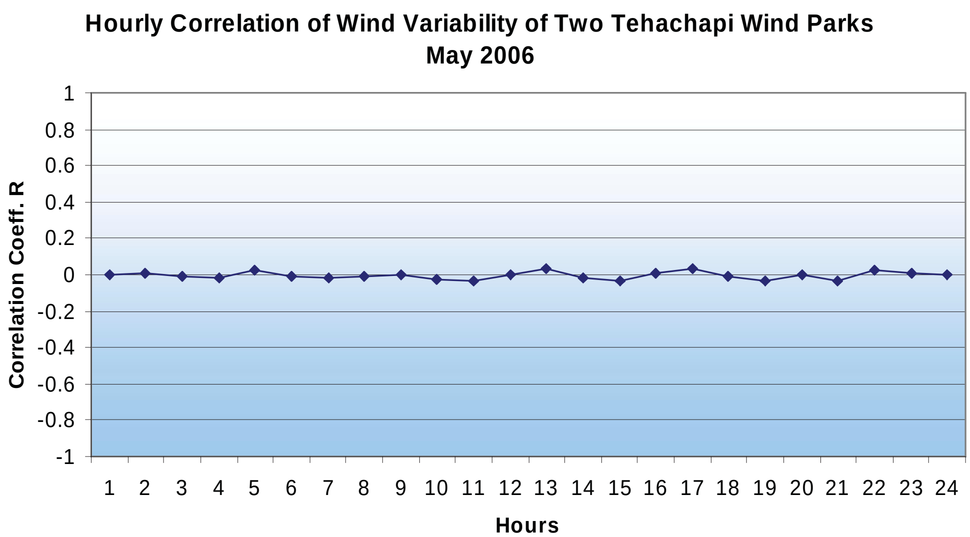


Figure D-5: Correlation of Short-Term Variations of Two Wind Parks in Tehachapi Resource Area

Since the variability of the parks is independent, the standard deviations are added together as the square root of the sum of the squares. The scale factor γ is then determined by calculating the expected standard deviation and dividing that by the current standard deviation:

$$\gamma = \frac{\sqrt{\frac{MW_{2010}}{MW_{2006}}\sigma^2}}{\sigma} = \sqrt{\frac{MW_{2010}}{MW_{2006}}}$$

The minute-to-minute variation is then multiplied by this scaling factor for each minute to get the expected variability. The variability from one of the newer wind park and the wind parks connected to the Vincent substation were analyzed separately. These two wind parks were used in the analysis because real-time telemetry from these sites are updated and sent to the California ISO every 4 seconds. The newer wind park (60 MW) is made up of newer wind turbines, and it is assumed that future additions will behave similarly to the turbines installed at this park. Thus, the scaling was split so that the newer wind park minute-to-minute variability was scaled such that it represents 75% of the expected Tehachapi addition. The Vincent substation variability was scaled to represent the remaining 25%. The scaled variabilities were added together minute-by-minute to give the total Tehachapi distribution. A similar method was used in the Solano area. For the Solano area, the two newest wind parks analyzed. Since both of these parks have relatively new wind turbine technology, an equal weight (50%) was placed on the variability of each. Finally, the energy component and the 1-minute variability were added together to give the 1-minute wind production values.

Appendix E — Wind Forecast Error

The 2-hour ahead wind forecast error was analyzed in order to give an estimate of the types of errors one could expect in the 2013 time frame which coincides with the build out of the 20% RPS goal. The wind forecast error is defined as a percentage of total installed wind park capacity and is calculated by taking the difference between the actual and forecast production for a given hour divided by the plants' capacity. The dataset used was provided by AWS Truewind, which provided the forecast error for June 2006 through May 2007. The statistics for the forecast error were also calculated for each time frame and are summarized in Table E-1. In addition to the seasonal statistics, the mean absolute percent error (MAPE) was also calculated to be 5.94% for the entire time period.

$$\varepsilon = \frac{Actual - Forecast}{Capacity}$$

$$MAPE = \frac{1}{N}\sum_{i=1}^{i=N} |\varepsilon_i|$$

Additionally, the autocorrelation error (*R*) was calculated to see if the forecast errors are time dependent (i.e., is the forecast wind generation typically under-forecast or over-forecast for certain time periods?) The autocorrelation depends on the number of observations, the standard deviation of the observations, the sample mean and the current and next observation. Autocorrelation has values between -1 and 1. A value of 1 indicates that the next value has a very strong positive dependence on the previous value, while a value of -1 indicates that the next value has a strong negative dependence on the previous value. An autocorrelation value of 0 indicates that the current value gives no indication of what the next value will be.

$$R = \frac{1}{(n-1)\sigma^2}\sum_{i=1}^{n-1}(X_i - \mu)(X_{i+1} - \mu)$$

Where: n is the number of occurrences
X is the value of the error at that time
μ is the average value of the error
σ is the standard deviation of the error

Table E-1: Summary of Wind Forecast Error

	Average	Minimum	Maximum	Standard Deviation	Autocorrelation
Winter	0.00	-0.36	0.31	0.07	0.61
Spring	0.00	-0.43	0.31	0.09	0.71
Summer	0.00	-0.32	0.31	0.08	0.65
Fall	0.00	-0.32	0.40	0.08	0.59

Finally, the statistical distribution of the forecast error was analyzed. It was compared to a truncated normal distribution. The truncated normal distribution is very similar to a normal distribution, but differs in that its extremities are bounded or truncated. The truncated normal distribution is more practical for real datasets that cannot have infinite values. For example, we would not expect the wind forecast error to exceed the plant capacity. It is a piecewise function, ensuring that there is no chance of a value occurring outside the bounds, which is rescaled by the normal distribution to give an area under the curve of 1. The formula for the truncated normal distribution is given below.

$$PDF_{TND}(\varepsilon) = \begin{cases} 0, & -\infty \le \varepsilon < \varepsilon_{\min} \\ \dfrac{PDF_N(\varepsilon)}{\displaystyle\int_{\varepsilon_{\min}}^{\varepsilon_{\max}} PDF_N(\varepsilon)\, d\varepsilon}, & \varepsilon_{\min} \le \varepsilon \le \varepsilon_{\max} \\ 0, & \varepsilon_{\max} \le \varepsilon \le +\infty \end{cases}$$

$$PDF_N(\varepsilon) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-\frac{1}{2}\left(\frac{\varepsilon - \varepsilon_0}{\sigma}\right)^2}, \quad -\infty \le \varepsilon \le +\infty$$

The truncated normal distribution is a good fit for the data as shown in the following Figures E-1a, E-1b, E-1c & E-1d.

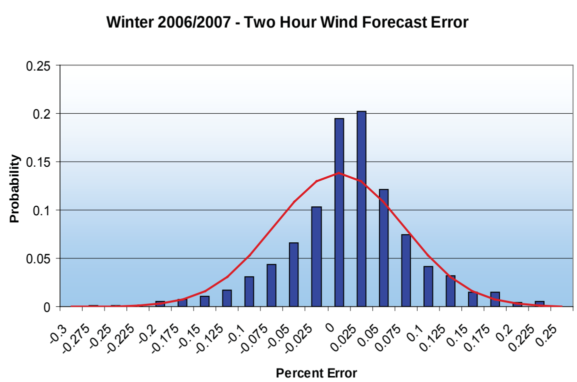


Figure E-1a: Winter Forecast Error

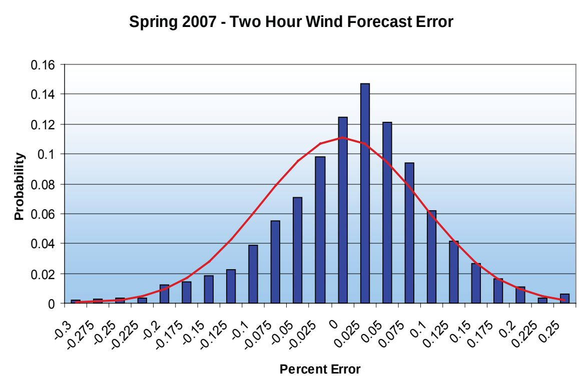


Figure E-1b: Spring Forecast Error

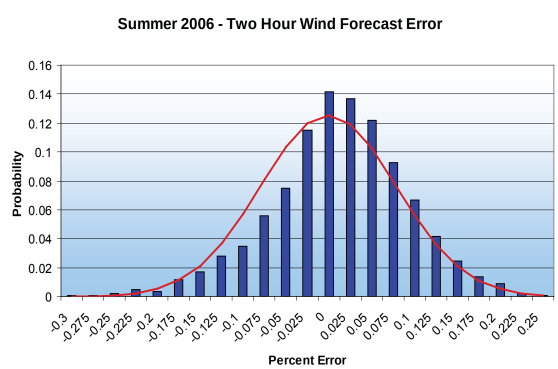


Figure E-1c: Summer Forecast Error

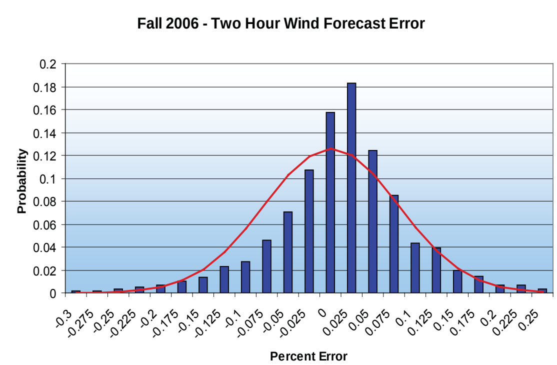


Figure E-1d: Fall Forecast Error

Appendix F Wind Turbine Generator Modeling

1. Power Flow Model

The modeling of a wind plant for load flow analysis is simple. Wind plants normally consist of a large number of individual wind turbine generators (WTGs). The wind plant model may consist of a detailed representation of each WTG and the collector system. Alternatively, the simpler model shown in Figure F-1 is adequate for most bulk transmission system studies. This model consists of a single WTG and unit transformer with MVA ratings equal to **N** times the individual device ratings, where **N** is the number of WTGs in the wind plant (or those considered to be online for study purposes). An equivalent impedance to reflect the aggregate impact of the collector system can be included together with the substation step-up transformer(s). The total charging capacitance of the collector system can also be included. The charging capacitance can be significant since underground cables are often used for the collector system. A third alternative is to model several groups of WTGs, each represented by a single model, with a simplified representation of the collector system. The wind plants included in this study use both of these equivalent modeling approaches.

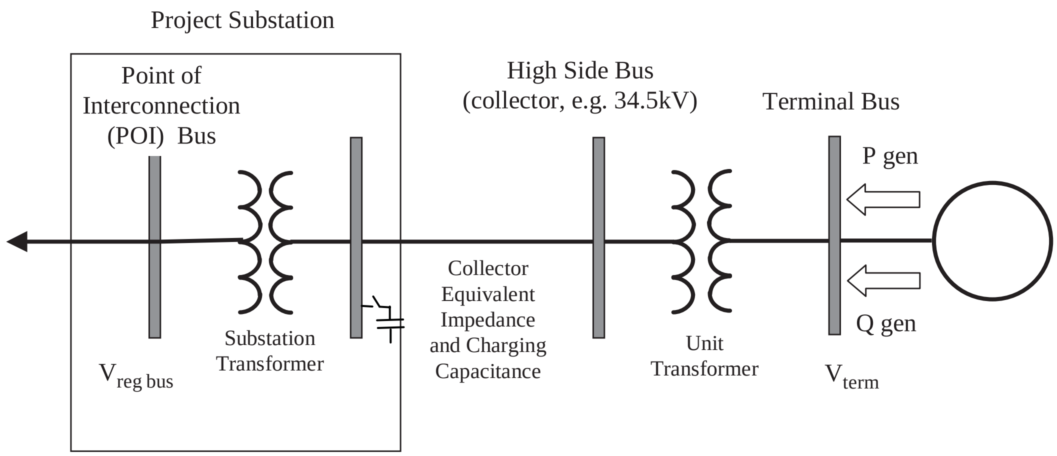


Figure F-1: Wind Plant Equivalent Model

From an analysis perspective, it is important to understand that the aggregate WTG behaves like a conventional generator connected to a (PV) bus in the power flow analysis. The generator Pgen, Qmax and Qmin are input to reflect the aggregate WTG capability. Typical collector system voltages are at distribution levels (12.5 kV or 34.5 kV are common). The substation transformer is suitably rated for the number of WTGs. Some of the wind plant models in this study include shunt capacitors on the collector side of the substation transformer, as illustrated in Figure F-1. These capacitors replace or augment reactive capability from the WTGs, so that the power factor requirement of the grid code is met.

2. Dynamic Model

2.1. WECC Standard Models

Dynamic modeling of wind generation, particularly newer technology WTGs, is a challenge for the industry. The Western Electricity Coordinating Council (WECC) Modeling & Validation Work Group (MVWG) convened a Wind Generator Modeling Group (WGMG) in 2005 to address the challenge. The charter of that group is to "develop a small set of generic (non-vendor specific), non-proprietary, positive-sequence power flow and dynamic models suitable for representation of all commercial, utility-scale WTG technologies in large scale simulations." The models are suitable for typical transmission planning and system impact studies. All of the current commercially available utility scale wind turbines can be grouped into four basic topologies based on how they interface with the grid. The notation that the WG adopted, which is gaining industry acceptance, is as follows:

Type 1 – conventional induction generator

Type 2 – wound rotor induction generator with variable rotor resistance

Type 3 – doubly-fed induction generator

Type 4 – full converter interface

Simple schematics of these four topologies are shown in Figure F-2.

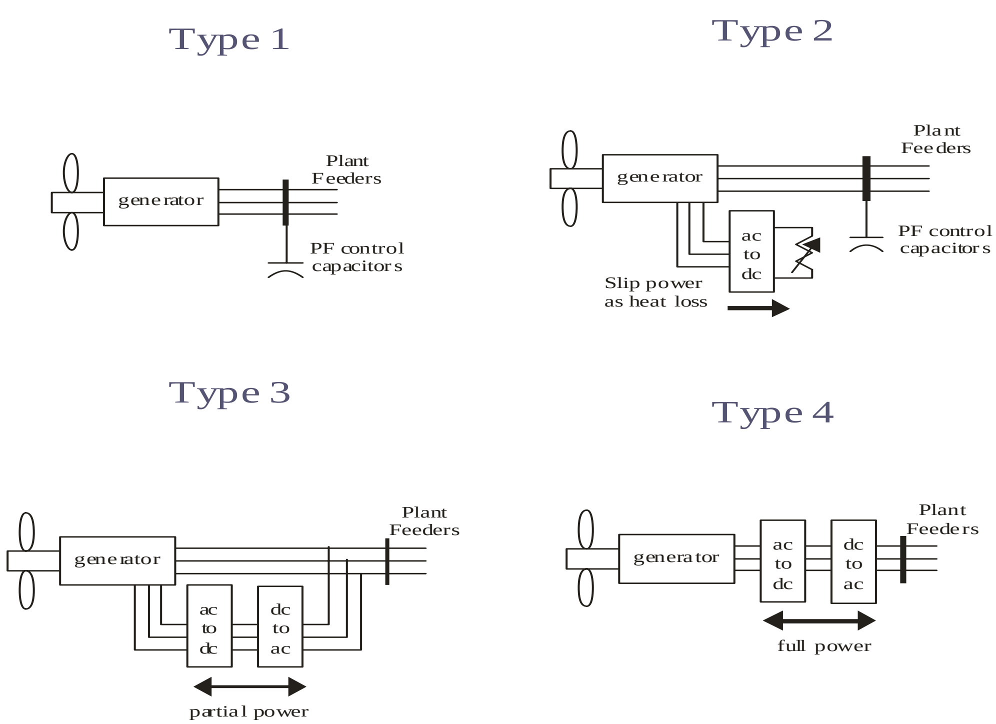


Figure F-2: WECC Standard Wind Turbine Model Types

2.2. GE PSLF WTG Models

From a system perspective, there are some important differences between these four types of WTGs. The GE PSLF user's manuals include different sets of default control models that can be used to build dynamic models of WTGs for transmission planning studies. Table F-1 lists the GE PSLF model names and the corresponding components of the WTG, proposed in GE WTG Modeling Version 3.3. The detailed control block diagrams are also shown in the GE PSLF user's manuals.

Table F-1: GE PSLF Control Models for WTG

Type of WTG	PSLF Model Name	WTG Component	Explanation
Type 1	motor1	Induction generator	This is an induction machine represented in load flow working case as a generator.
Type 2	genwri	Conventional-technology wound rotor induction (WRI) machine	This needs to be used with an external field resistor.
	exwtg1	External field resistor for the WRI	Normally, the resistor is electronically controlled (with a PWM IGBT circuit). The function of this control is to provide a much more steady power output from the wind turbine.
	wndtrb	Wind Turbine Model	Provides a simple representation of a complex electro-mechanical system to extract as much power from the available wind as possible without exceeding the rating of the equipment.
Type 3 (Note: GE has published different versions of Type 3 modeling using the same model names)	gewtg	Generator/Converter	This is equivalent to the generator and the field converter and provides the interface between the WTG and the network.
	exwtge	Electrical (Converter) Control Model	This dictates the active and reactive power to be delivered to the system based on inputs from the turbine mode and from the supervisory Var controller.
	wndtge	Wind Turbine and Turbine Control Model	This provides a simplified representation of the relevant controls and mechanical dynamics of the wind turbine.

2.3. Reactive Power Characteristics

Type 1 machines operate in a very narrow speed range, and always consume reactive power during operation. The reactive power consumption is a function of active power production and grid conditions, and it cannot be controlled. Consequently, both the reactive power consumption of the generator *and* the reactive power requirements of the grid, must be supplied by additional equipment — usually switched shunt capacitors.

Type 2 machines have wider speed variation and tend to exhibit slower active power fluctuations than type 1 machines, but have similar reactive power characteristics. Under load, the machines consume reactive power equal to approximately half of the MW output.

Type 3 and Type 4 machines use substantial power electronics to provide wider speed range and finer control of active power production. The power electronics also inherently provide the ability to produce or consume reactive power. It is largely controllable independent from the active power production. In this regard, these machines resemble conventional synchronous generators with excitation systems and automatic voltage regulators (AVR). The details of performance are different between manufacturers. Generally, wind plants with Type 3 or Type 4 generators have the ability to provide relatively fast voltage or power factor control. The ways in which each manufacturer controls and coordinates the reactive power production and balance differs. The great majority of wind generation built in the U.S. last year was of Type 3 or 4.

2.4. Low Voltage Ride-Through (LVRT)

Figure F-3 shows the WECC LVRT performance requirements and the PSLF implementation used in this study. For Type 3 and Type 4 WTGs, the ability to tolerate severe low voltages is primarily an issue of control and toughening of the power electronics necessary for operation of the wind turbines. For Type 1 and Type 2 machines, LVRT capability is derived from increased robustness of auxiliaries and contactors. It is important to recognize that LVRT capability and compliance is specific to voltage deviations during and immediately following grid faults and disturbances. LVRT compliance does not guarantee that wind plants will remain stable following severe upsets.

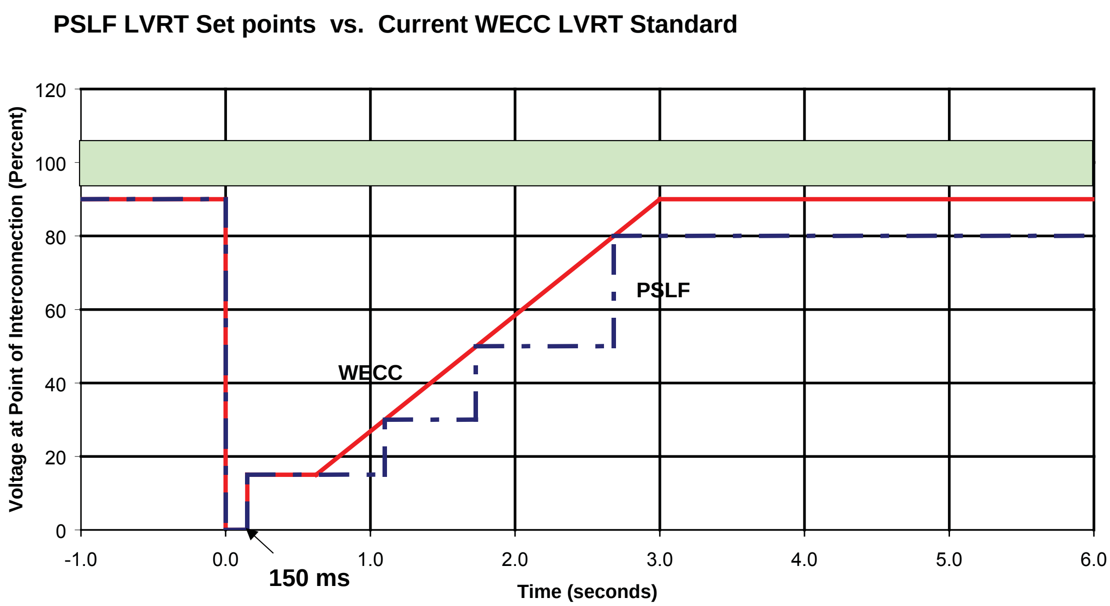


Figure F-3: LVRT Requirements and Modeling

3. Generator Protection Model

WTGs may be tripped for voltages and frequency values that exceed specified thresholds for specified time durations. Both the voltage and frequency trips should typically include a circuit breaker time of 0.15 seconds. In particular, the low voltage tripping will be set to meet LVRT requirements. WTGs from different manufacturers may have different protection models.

GE PSLF has provided methods to simulate the protection model for Types 2, 3 and 4 of WTG models.

Note: For the GE 1.5 MW WTG, the measurement point of the generator protection is the terminals of the generator. For the GE 3.6 MW WTG, the measurement point is at the high side of the unit step-up transformer.

3.1. Use Generator/Converter Model in Version 3.3 WTG Model

Table F-2 illustrates the GE PSLF variables corresponding to the "gewtg" control model for the Type 3 WTG model provided in GE WTG model Version 3.3. The LVRT settings used in this study are also listed in Table F-2.

Table F-2: Voltage Trip Level Setting in "gewtg" Model of GE WTG Model Version 3.3

EPCL Variable	Tripping Level	Description
dVtrp1	-0.15	Delta voltage trip level, p.u.
dVtrp2	-0.25	Delta voltage trip level, p.u.
dVtrp3	-1.0	Delta voltage trip level, p.u.
dVtrp4	0.1	Delta voltage trip level, p.u.
dVtrp5	0.15	Delta voltage trip level, p.u.
dVtrp6	0.3	Delta voltage trip level, p.u.
dTtrp1	10	Voltage trip time, sec. (10 for no tripping)
dTtrp2	0.15	Voltage trip time, sec.
dTtrp3	0.01	Voltage trip time, sec.
dTtrp4	1.0	Voltage trip time, sec.
dTtrp5	0.1	Voltage trip time, sec.
dTtrp6	0.02	Voltage trip time, sec.

3.2. Use User-defined Model in Version 3.4 WTG Model

In GE PSLF WTG model Version 3.4, the WTG protection relay can be modeled through a standard user-written EPCL. Generator protection model (**gpwtg.p**) is available in GE PSLF for modeling voltage and frequency tripping. WTG from different manufacturers can be modeled using different EPCL protection models. The user-defined protection model can be used for both Types 2 and 3 WTGs.

The voltage trip levels are similar to those shown in Table F-2. The typical frequency trip levels and durations based on specifications for a 60 Hz, 1.5 MW unit are shown in Table F-3.

Table F-3: Typical WTG Generator/Converter Frequency Trip Levels and Times (for 60 Hz. systems)

f (Hz.)	freq. [p.u.]	Time [sec]
57.5	0.96	30
56.5	0.94	.02
61.5	1.025	31
62.5	1.04	.02

Appendix G Tehachapi Transmission Plan

California's largest potential for the development of wind generation is the Tehachapi area, which lies at the southern end of the San Joaquin Valley in the mountainous region between Bakersfield and Mohave. It is expected that at a minimum, 4,350 MW of wind generators could be installed in this area. As a result, the Tehachapi Collaborative Study Group (TCSG) was formed in 2004 to create a comprehensive transmission development plan for the phased expansion of transmission capabilities in the Tehachapi area. The California Public Utilities Commission (CPUC) staff coordinated the TCSG, while Southern California Edison Company (SCE) sponsored the project pursuant to the terms of the California ISO's Large Generator Interconnection Procedures.

The first report from the TCSG was issued to the CPUC in March 2005. In that report, the TCSG identified a number of alternatives for the transmission infrastructure and recommended further study be conducted in order to select the best expansion plan. A second report was issued in April 2006, which narrowed and refined the transmission infrastructure alternatives submitted in the first report. The second report also recommended that in order to facilitate completion of the planning process further, detailed technical studies of the alternatives were to be performed by the California ISO.

The California ISO studied the Tehachapi Transmission Project as part of its California ISO South Regional Transmission Plan for 2006 (CSRTP-2006) in full collaboration with SCE and other CSRTP-2006 participants. The studies were "clustered", which allowed the California ISO to collectively assess the system impacts of a group of interconnection requests, rather than evaluate each potential generation facility individually. By "clustering" the interconnection request, a least-cost solution for the transmission infrastructure was determined to interconnect up to 4,350 MW of planned generation projects in the Tehachapi area to the California ISO-controlled grid. This transmission expansion plan was approved by the California ISO Board in January 2007.

1. Benefits of the Tehachapi Transmission Project

The benefits of the Tehachapi Transmission Project as approved by the California ISO Board in January 2007, are as follows:

1. The Tehachapi Transmission Project is the least-cost solution that reliably interconnects 4,350 MW of generating resources in the Tehachapi area.
2. The Tehachapi Transmission Project also addresses the reliability needs of the California ISO- controlled grid due to projected load growth in the Antelope Valley area and helps to address South of Lugo (SOL) transmission constraints — an ongoing source of reliability concern for the Los Angeles (LA) Basin.
3. The Tehachapi Transmission Project facilitates the ability of California utilities to comply with the state-mandated Renewables Portfolio Standard (RPS) by providing access to planned renewable resources in the Tehachapi Wind Resource Area (TWRA)

4. The Tehachapi Transmission Project is expected to provide economic benefits to the California ISO ratepayers, primarily by offering access to wind and other efficient generating resources under development in TWRA.
5. The Tehachapi Transmission Project makes it possible to expand the transfer capability of Path 26 in the near future with a low-cost upgrade of PG&E's portion of Midway-Vincent Line 3.
6. The Tehachapi Transmission Project will be used by other projects in the generation queue beyond the start date of the CSRTP-2006 for low-cost interconnection to the California ISO Controlled Grid.
7. Although the detailed planning has not yet been performed, the Tehachapi Transmission Project lays the groundwork for the integration of large amounts of planned geothermal, solar and wind generation in Inyo and northern San Bernardino counties with potential future 500 kV additions from the Wind Hub Substation (one of the Tehachapi Transmission Project's substations) to the Kramer Substation.

   The Tehachapi Transmission Project will accommodate all targeted generation projects in the Tehachapi Area Generator queue. However, sufficient flexibility is built into the rollout of the Tehachapi Transmission Project to reasonably respond to changes in the magnitude and the location of generation resources in the area.

2. Project Description and Schedule

Figure G-1 depicts the major components of the Tehachapi Transmission Project at full build out in 2013, while Table G-1 sets forth the schedule for the rollout of the major components. Due to the expansive nature of the Tehachapi Transmission Project, the components of this infrastructure will be developed and put into service over a 5-year period starting in 2008. The addition of each component allows increased access to generation and ensures compliance with reliability standards given projected load growth in the area. This schedule is intended to be flexible and subject to change in response to actual wind generation development in the TWRA.

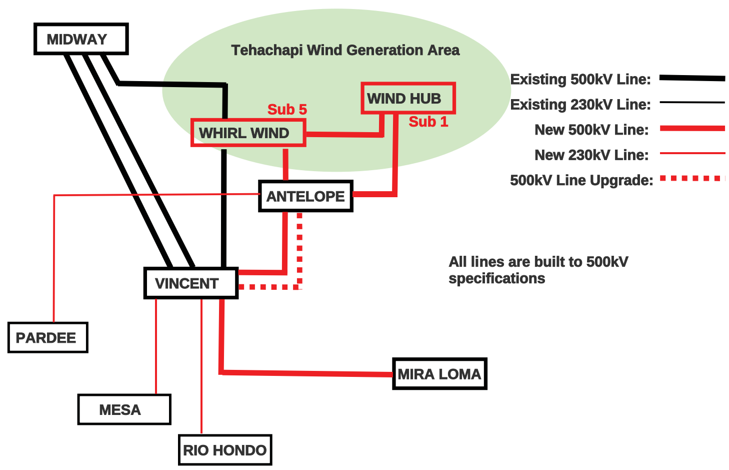


Figure G-1: Proposed Transmission Upgrades

3. New or Upgraded Substations

Three new substations would be constructed and used as collector stations for the wind farms in the TWRA: Wind Hub, Whirl Wind and High Wind Substations. The first two of the three new substations are part of the network component of the overall plan of service. The cost of the third substation (High Wind) is the responsibility of the wind developers and not included in the Tehachapi Transmission Project plan.

Wind Hub 500/230/66 kV will include up to four 500/230 kV transformer banks, four breaker-and-half 500 kV bus positions, six initial breaker-and-half 230 kV bus positions, static voltage support devices, and dynamic voltage support if necessary. Additional equipment will be added as wind generation develops in the region.

Whirl Wind 500/230 kV will include up to two 500/230 kV transformer banks, four breaker-and-half 500 kV bus positions, three initial breaker-and-half 230 kV bus positions, static voltage support devices and dynamic voltage support if necessary. It also includes loop in of Midway-Vincent #3 line to connect the substation to the grid. Additional equipment will be added as wind generation develops in the region.

4. Upgrades to Existing Substations

- The Pardee 230/66 kV substation will be upgraded by outfitting existing 230 kV line position.
- The existing Mira Loma 500/230/66 kV substation will be upgraded by outfitting existing 500 kV line position.
- The existing 230/66 kV Antelope Substation will be expanded to include a new 500 kV switchyard, additional 230 kV line positions and static and dynamic voltage support.
- The existing 500/230 kV Vincent Substation will be expanded to include additional 500 kV and 230 kV line positions, additional static and dynamic voltage support and additional 500/230 kV bank capacity.
- The Mesa 230/66 kV substation will be upgraded by outfitting existing 230 kV line position.
- The Gould 230/66 kV substation will be upgraded by outfitting existing 230 kV line position.

5. New or Upgraded Transmission Lines

- New 25.6-mile 500 kV transmission line between Antelope and Pardee substations initially operated at 230 kV. This line is also known as Phase 1-Segment 1 of the original Antelope Transmission Project. Construction to 500 kV specifications with initial operation at 230 kV is required to maximize the capability of limited transmission corridors and minimize environmental impacts associated with multiple 230 kV lines and/or multiple teardown and rebuild activities. Actual operation of 500 kV will be determined by the amount of generation build out in the system and changes to system conditions.

- New 25.6-mile 500 kV transmission line between Wind Hub and Antelope substations. This line is also known as Phase 1-Segment 3 of the original Antelope Transmission Project and will initially operate at 230 kV.

- Two new 500 kV transmission lines between Antelope and Vincent substations. The initial 500 kV transmission line will be approximately 21 miles, built on new right-of-way, mostly adjacent to the existing right-of-way. This line is also known as the Phase 1-Segment 2 of the original Antelope Transmission Project and will initially operate at 230 kV. This new transmission line is primarily required to meet the reliability needs of the California ISO-controlled Grid due to projected load growth in Antelope Valley. The second 500 kV transmission line will be approximately 18 miles, built on existing right-of-way, replacing the existing Antelope-Vincent and Antelope-Mesa 230 kV transmission lines. This transmission line will also be initially operated at 230 kV.

- New 75-mile 500 kV transmission line between Vincent and Mira Loma substations. This transmission line is required to eliminate the South of Lugo transmission constraints, which have been a source of ongoing reliability concern for the L.A. basin, especially in light of projected load growth in the Mira Loma area, and is planned to go into service by the 2012 time frame. This line will utilize the existing Vincent-Rio Hondo No. 2 230 kV transmission line (portion already built to 500 kV standards), a portion of the existing Antelope-Mesa 230 kV South of Vincent, portions of existing idle 230 kV transmission line segments, and portions of new construction between the Mesa area and Mira Loma area. Between Vincent and the northern boundary of the City of Duarte (adjacent to Angeles National Forest), the transmission line will be constructed as single-circuit 500 kV specifications. From this point to the Mira Loma area, the transmission line will be constructed as double circuit 500 kV specifications to maximize the capability of limited corridors and to minimize environmental impacts associated with multiple 230 kV lines and/or multiple tear-down and rebuild activities.

- New 32.5-mile 500/230 kV transmission line between Vincent and Rio Hondo is required to replace the existing Vincent-Rio Hondo No.2 230 kV transmission line that was utilized for the new Vincent-Mira Loma 500 kV transmission line. This line will utilize a portion of the existing Antelope-Mesa 230 kV transmission line and will be built to 500 kV specifications to maximize capability of limited transmission corridors, avoid waste and minimize environmental impacts associated with multiple 230 kV transmission lines and/or multiple tear-down and rebuild activities. As discussed above, such construction standard will allow for a future low cost upgrade to 500 kV operation.

- New 14-mile 500 kV transmission line between proposed Whirl Wind and the upgraded Antelope substations.

- New 42-mile 500/230 kV transmission line between Vincent and Mesa substations. Between Vincent and the Gould substation areas, this line will be built to 500 kV specifications to maximize capability of limited transmission corridors and minimize environmental impacts associated with multiple 230 kV transmission lines and/or multiple tear-down and rebuild activities and to allow for future low cost upgrade to 500 kV operation.

Table G-1: Tehachapi Transmission Project Plan of Services

Major Transmission Facilities	Planned In-Service Date
Antelope – Pardee 230 kV Line (500 kV specifications) & Antelope Substation expansion	Dec. 2008
Antelope – Vincent 230 kV Line #1 (500 kV specifications)	Mar. 2009
Wind Hub Substation	Mar. 2009
Antelope – Wind Hub (also known as Substation 1) 230 kV Line (500 kV specifications)	Mar. 2009
Antelope – Vincent 230 kV Line #2 (500 kV specifications)	Mar. 2011
Low Wind 500/230 kV Substation (also known as Substation 5) with Loop in of Midway – Vincent #3 500 kV line	Aug. 2011
Antelope – Whirl Wind 500kV line	Aug. 2011
Wind Hub Substation 500 kV upgrade	Mar. 2011
Antelope Substation 500 kV upgrade	Mar. 2011
Vincent Substation 500 kV & 220 kV upgrade	Sep. 2011
Whirl Wind – Wind Hub 500 kV line	Oct. 2011
Replacement of Vincent – Rio Hondo No. 2 230kV line	Nov. 2011
Vincent – Mira Loma 500 kV line	Apr. 2012
Vincent – Mesa 500/220 kV line and Mesa Substation work	Nov. 2013

6. List of Reactive Devices Required in the Tehachapi Area

In order to support 4,350 MW of generation in the Tehachapi area, a significant amount of reactive devices would be required. So far, studies done using a summer peak scenario identified the requirement for 2,000 MVARS of static shunt capacitors and 600 MVARS of SVC.

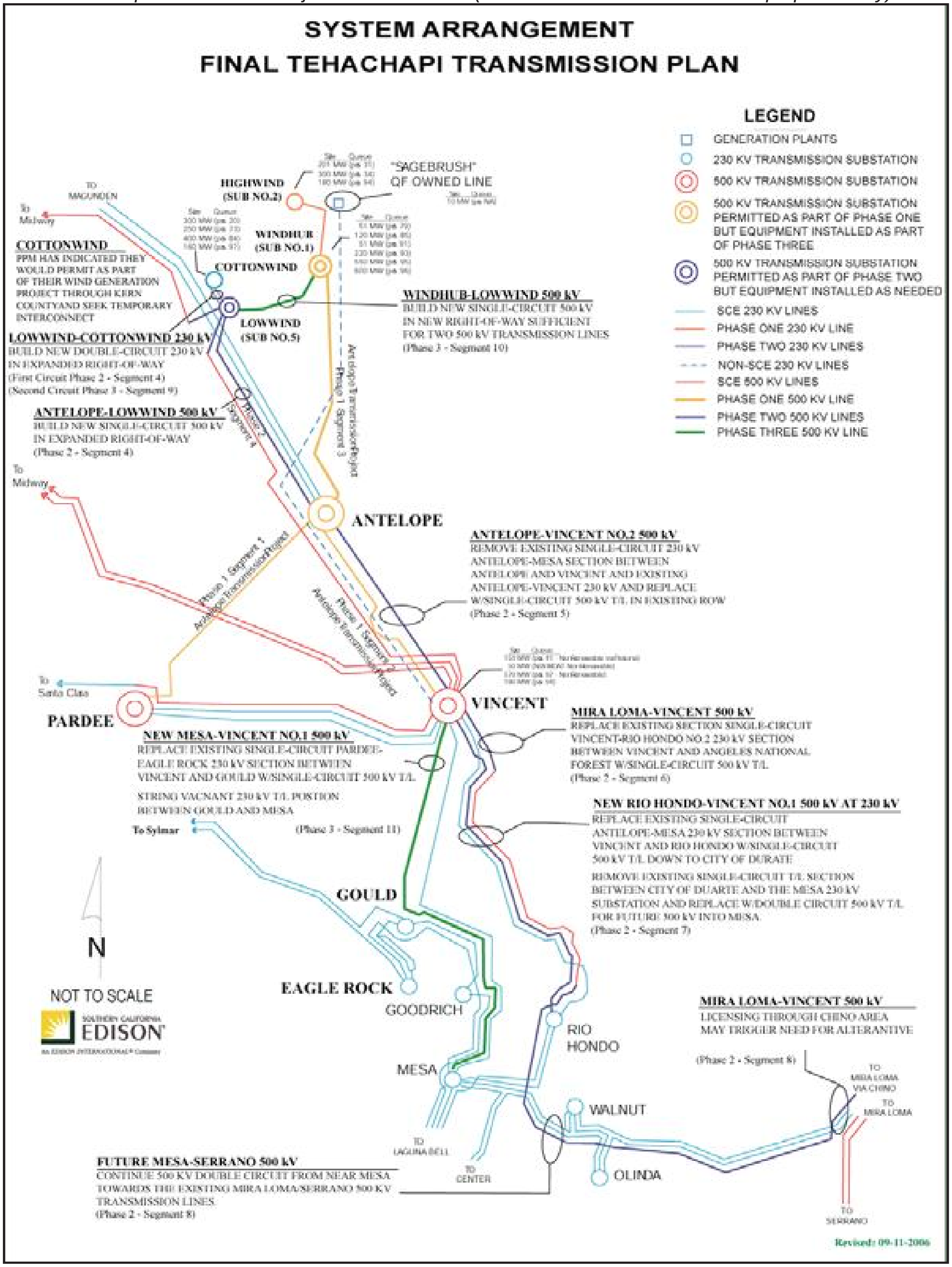
6.1 Static MVARS Requirement — 2,000 MVARS

- Vincent 500kV 400 MVAR shunt
- Antelope 500kV 400 MVAR shunt
- Sub. 5 (Whirl Wind) 500 kV 2x200 MVAR shunt
- Sub. 5 (Whirl Wind) 230 kV 2x100 MVAR shunt
- Sub. 1 (Wind Hub) 500 kV 2x200 MVAR shunt
- Sub. 1 (Wind Hub) 230 kV 2x100 MVAR shunt

6.2 Dynamic MVAR Requirement — 800 MVARS

- Vincent 500 kV 600 MVAR SVC
- Antelope 500 kV 200 MVAR SVC

Tehachapi Transmission Project Plan of Service (Routes shown are for illustration purposes only)



Appendix H — Transient Stability Plots

As stated in Chapter 3, one of the primary objectives of the transmission system analysis was to evaluate the transient stability performance of the California ISO-controlled Grid with an increased level of wind generation in the Tehachapi area.

The baseline analysis for all studies was performed assuming that all new wind plants would be equipped with the WECC Type 3 doubly fed wind turbine generators. The existing wind plants in the Tehachapi area were modeled as WECC Type 1 conventional induction generators. A total of 25 contingencies (11 Category B[1] and 14 Category C[2]) were simulated for each of the seasonal wind generation scenarios and three wind conditions (full, low and no wind). In addition, several sensitivity studies were performed by varying the mix of the WTG technologies of the new plants based on the actual installations of new wind plants in the U.S. in 2006. The simulation consists of time-domain simulation following the disturbances to evaluate the system transient stability performance of the Grid based on "WECC Planning Standards, WECC Disturbance-Performance Allowable Effects on Other Systems."

The following plots are self explanatory and show six of the contingencies studied:

1. Heavy Summer: Loss of two Midway-Vincent 500 kV lines. 3-phase, 4-cycle fault at Midway 500 kV substation. Blue: Full wind, Red: Low wind and Green: No wind. (Refer to H-2 to H-9).

2. Heavy Summer: Loss of two Palo Verde generators. Blue: Full wind, Red: Low wind and Green: No wind. (Refer to H-10 to H-17).

3. Heavy Summer: Loss of the PDCI bipolar with north to south flows. Blue: Full wind, Red: Low wind and Green: No wind. (Refer to H-18 to H-25).

4. Heavy Summer: Sensitivity of system performance to WTG technology for the Midway-Vincent double line outage. 3-phase, 4-cycle fault at Midway 500 kV substation. Blue: Type 3 doubly fed induction generators, Red: Mixed technology and Green: Type 1 induction generators. (Refer to H-26 to H-33).

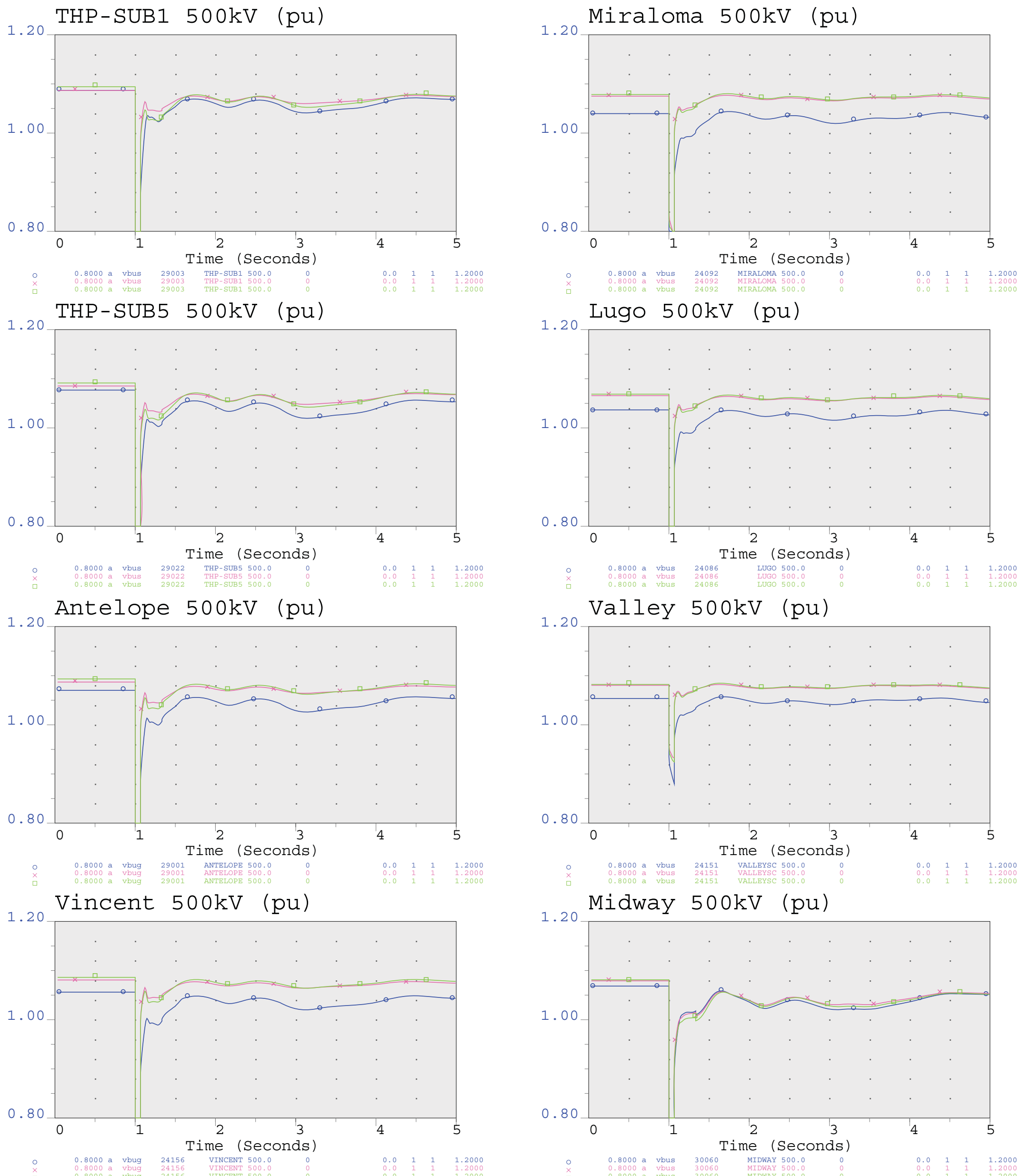
5. Light Spring: Loss of two Lugo-Vincent 500 kV lines. 3-phase, 4-cycle fault at Lugo 500 kV substation. Blue: Full wind, Red: Low wind and Green: No wind. (Refer to H-34 to H-41).

6. Light Spring: Loss of two Midway-Vincent 500 kV lines. 3-phase, 4-cycle fault at Midway 500 kV substation. Blue: Full wind, Red: Low wind and Green: No wind. (Refer to H-42 to H-49).

1 Category B is the loss of a single element.
2 Category C is event(s) resulting in the loss of two or more (multiple) elements.

500kV Voltages

Full Wind, Lo Wind, No Wind for Fault: 2010hs-Midway-Vincent-dlo-SPS



2010 HEAVY SUMMER POWER FLOW CASE
SUNRISE + TEHACHAPI PROJECTS - JULY 3, 2007
CAISO & GE COLLABORATIVE WIND STUDY
UPDATED NEW & EXISTING TEHACHAPI WIND GENERATION
3 phase 4 cycle fault at Midway
Loss of 2 Midway - Vincent Lines
No SPS

Page 1

a:2010hs-FullWind-Midway-Vincent-dlo-SPS.chf
b:2010hs-LoWind-Midway-Vincent-dlo-SPS.chf
c:2010hs-NoWind-Midway-Vincent-dlo-SPS.chf

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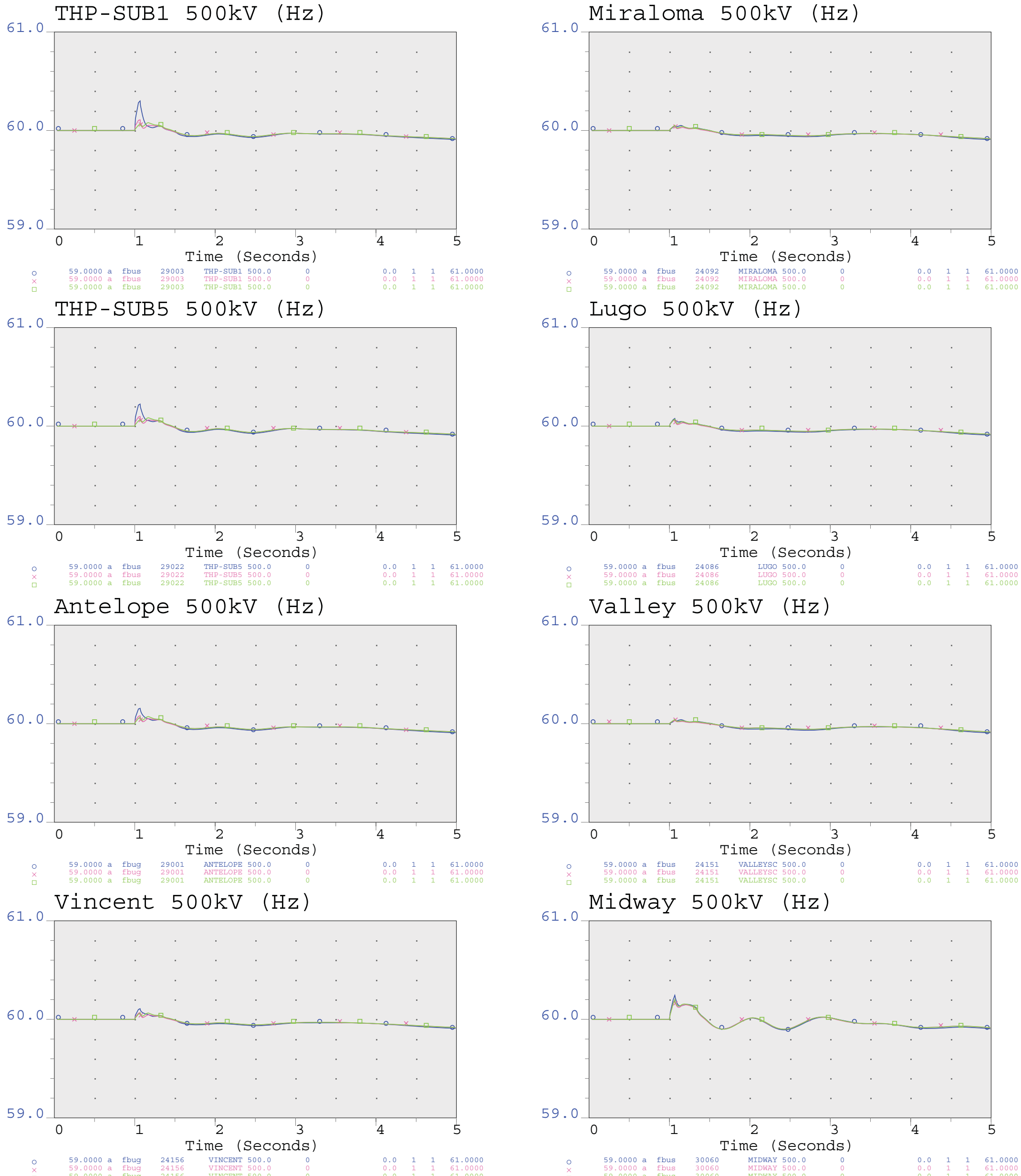
Wed Aug 22 11:21:14 2007

500kV Frequencies
Full Wind, Lo Wind, No Wind for Fault: 2010hs-Midway-Vincent-dlo-SPS



2010 HEAVY SUMMER POWER FLOW CASE
SUNRISE + TEHACHAPI PROJECTS - JULY 3, 2007
CAISO & GE COLLABORATIVE WIND STUDY
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Page 2

a:2010hs-FullWind-Midway-Vincent-dlo-SPS.chf
b:2010hs-LoWind-Midway-Vincent-dlo-SPS.chf
c:2010hs-NoWind-Midway-Vincent-dlo-SPS.chf

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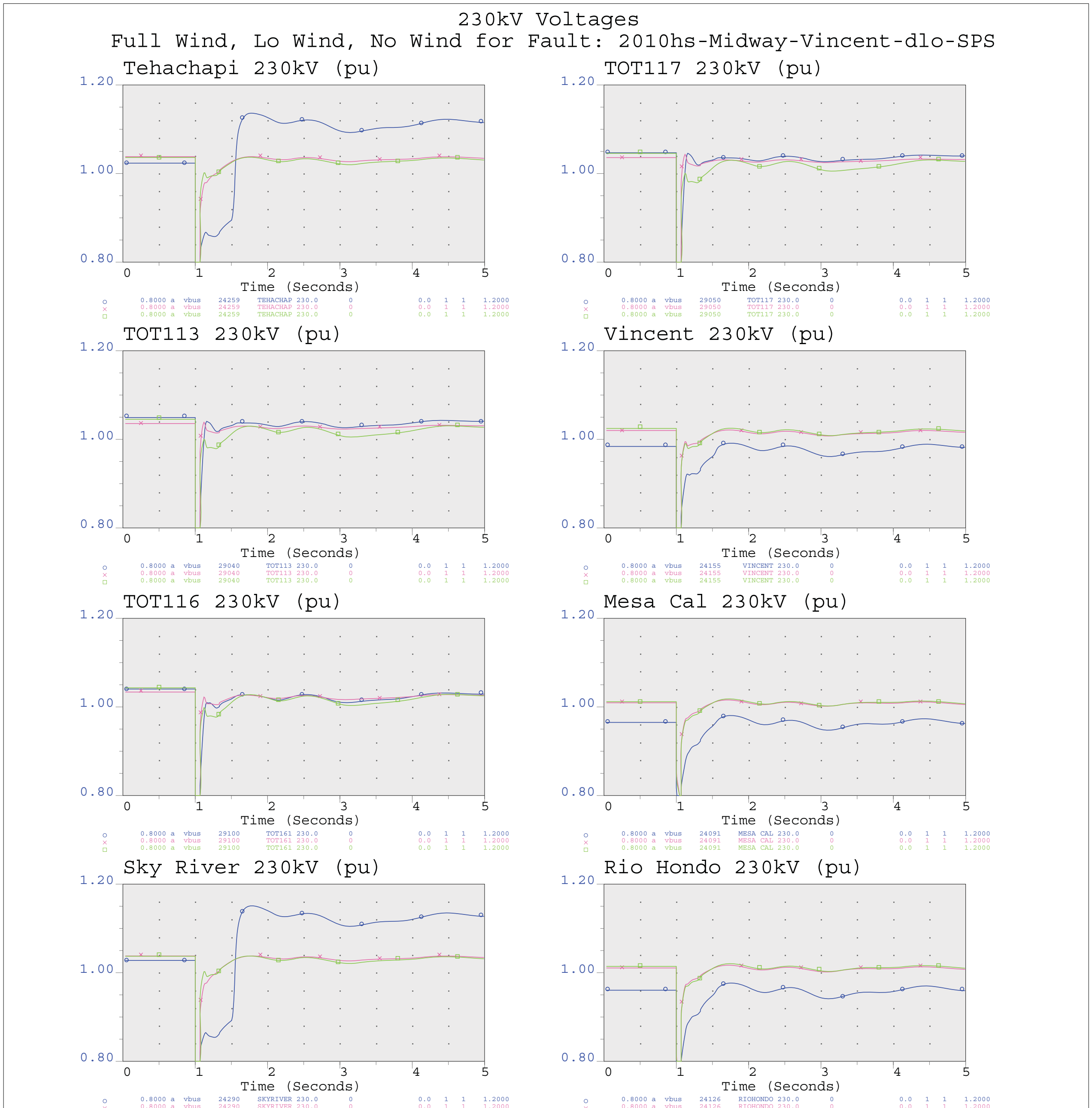

2010 HEAVY SUMMER POWER FLOW CASE
SUNRISE + TEHACHAPI PROJECTS - JULY 3, 2007
CAISO & GE COLLABORATIVE WIND STUDY
UPDATED NEW & EXISTING TEHACHAPI WIND GENERATION
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Page 3

a:2010hs-FullWind-Midway-Vincent-dlo-SPS.chf
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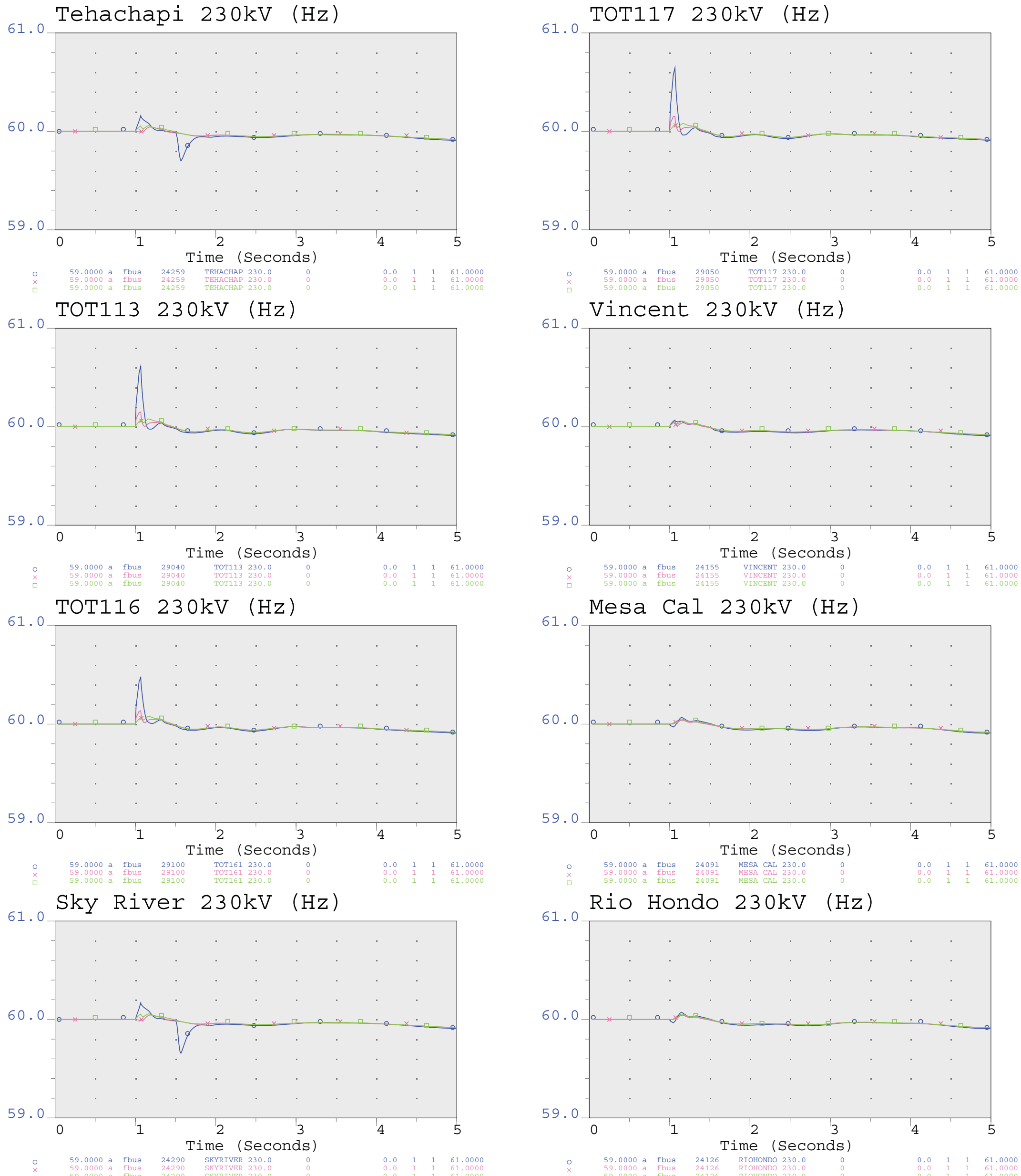
Wed Aug 22 11:21:14 2007

230kV Frequencies
Full Wind, Lo Wind, No Wind for Fault: 2010hs-Midway-Vincent-dlo-SPS



2010 HEAVY SUMMER POWER FLOW CASE
SUNRISE + TEHACHAPI PROJECTS - JULY 3, 2007
CAISO & GE COLLABORATIVE WIND STUDY
UPDATED NEW & EXISTING TEHACHAPI WIND GENERATION
3 phase 4 cycle fault at Midway
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Page 4

a:2010hs-FullWind-Midway-Vincent-dlo-SPS.chf
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c:2010hs-NoWind-Midway-Vincent-dlo-SPS.chf

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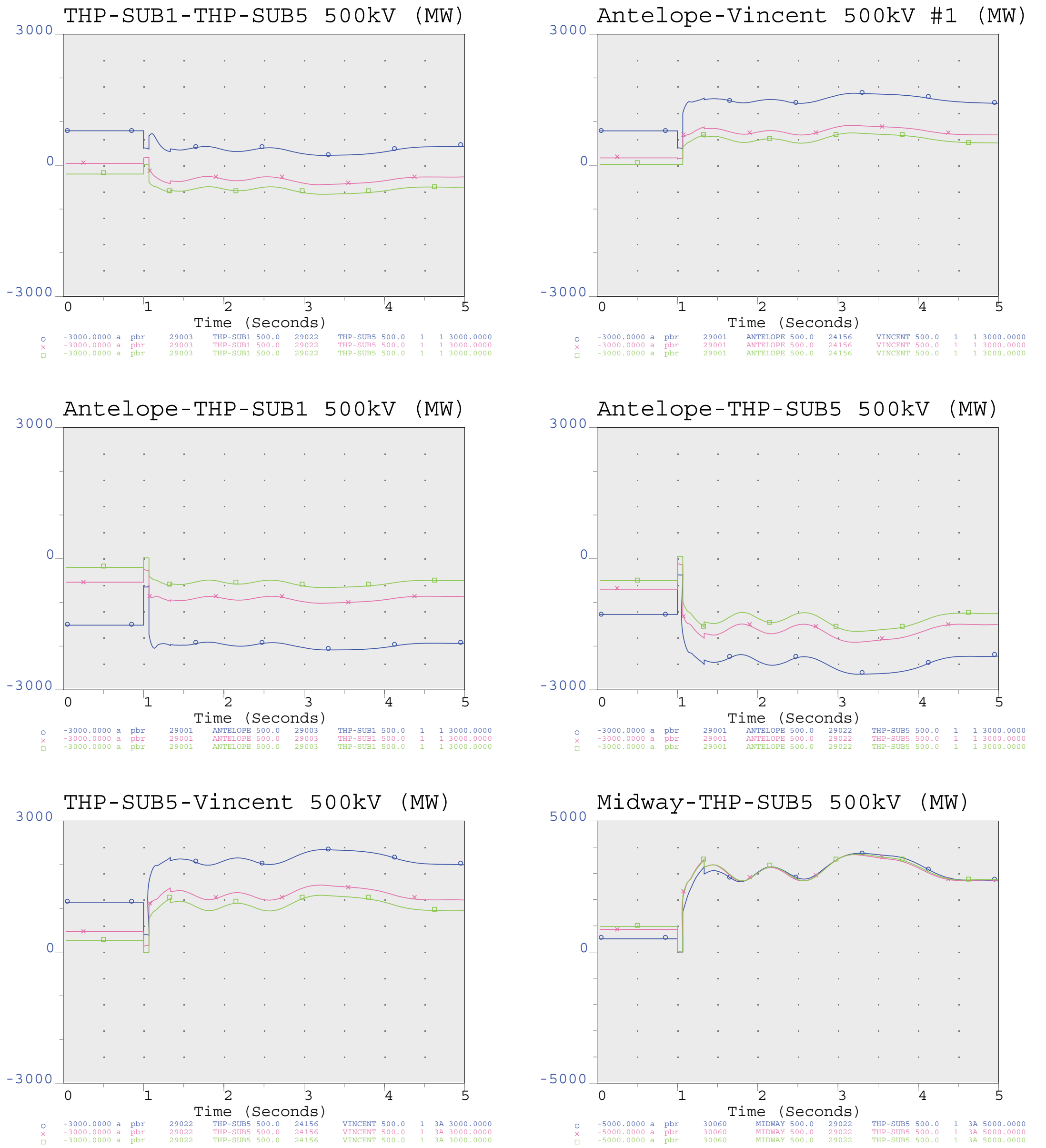
Wed Aug 22 11:21:15 2007

500kV Real Power Flows
Full Wind, Lo Wind, No Wind for Fault: 2010hs-Midway-Vincent-dlo-SPS



2010 HEAVY SUMMER POWER FLOW CASE
SUNRISE + TEHACHAPI PROJECTS - JULY 3, 2007
CAISO & GE COLLABORATIVE WIND STUDY
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Page 5

a:2010hs-FullWind-Midway-Vincent-dlo-SPS.chf
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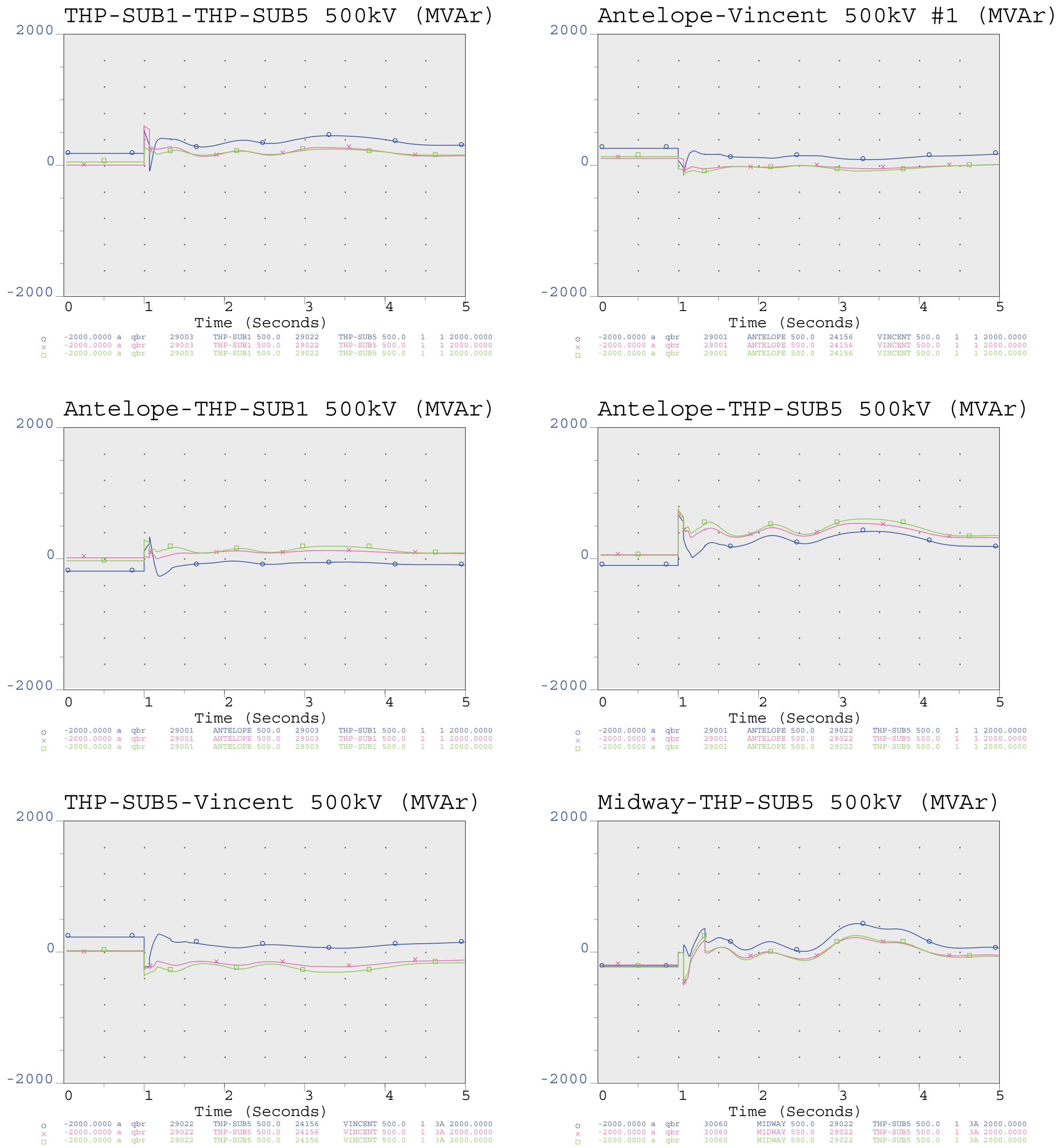
Wed Aug 22 11:21:15 2007

500kV Reactive Power Flows
Full Wind, Lo Wind, No Wind for Fault: 2010hs-Midway-Vincent-dlo-SPS



2010 HEAVY SUMMER POWER FLOW CASE
SUNRISE + TEHACHAPI PROJECTS - JULY 3, 2007
CAISO & GE COLLABORATIVE WIND STUDY
UPDATED NEW & EXISTING TEHACHAPI WIND GENERATION
3 phase 4 cycle fault at Midway
Loss of 2 Midway - Vincent Lines
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Page 6

a:2010hs-FullWind-Midway-Vincent-dlo-SPS.chf
b:2010hs-LoWind-Midway-Vincent-dlo-SPS.chf
c:2010hs-NoWind-Midway-Vincent-dlo-SPS.chf

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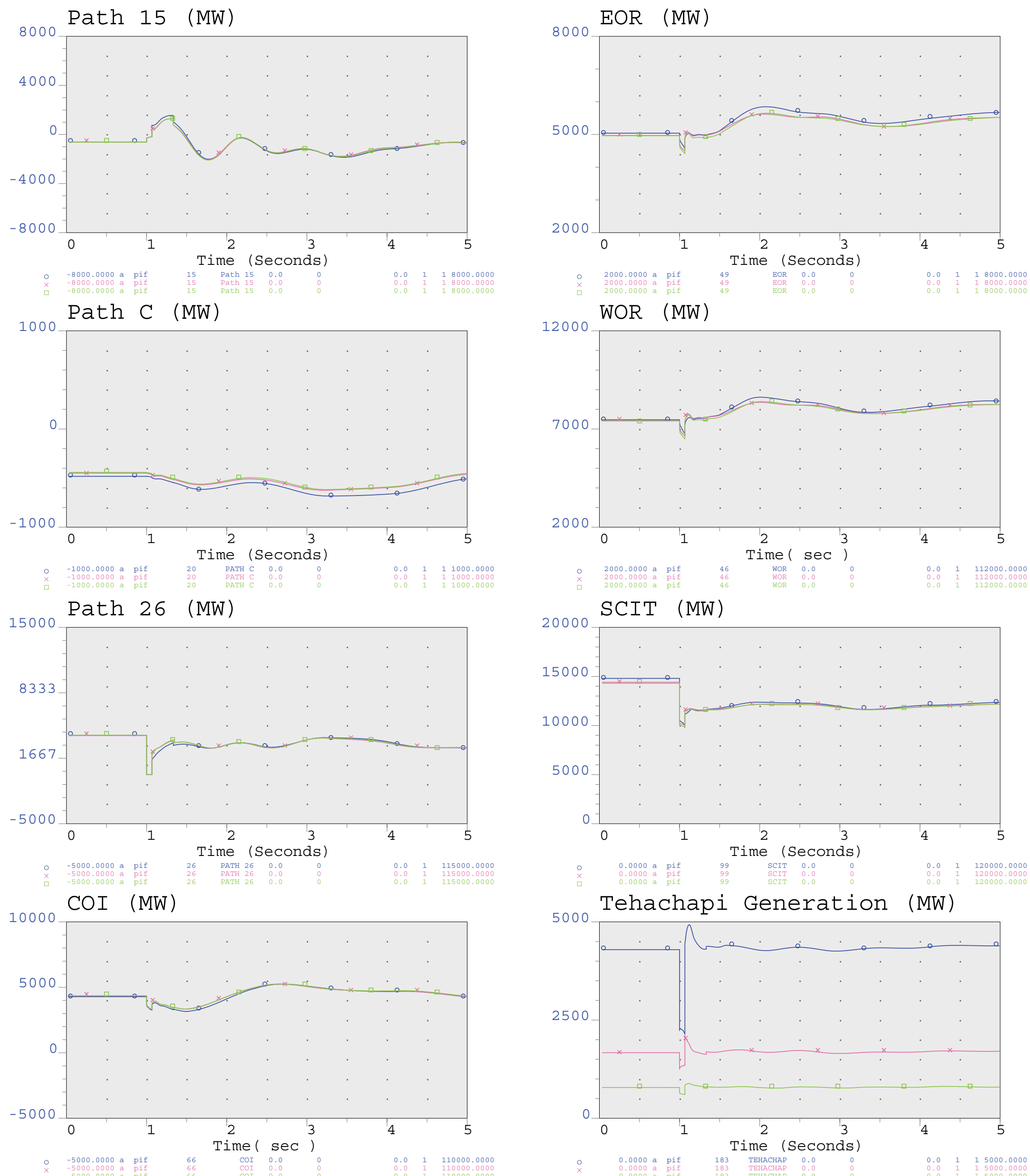
Wed Aug 22 11:21:15 2007

Interface Power Flows
Full Wind, Lo Wind, No Wind for Fault: 2010hs-Midway-Vincent-dlo-SPS



2010 HEAVY SUMMER POWER FLOW CASE
SUNRISE + TEHACHAPI PROJECTS - JULY 3, 2007
CAISO & GE COLLABORATIVE WIND STUDY
UPDATED NEW & EXISTING TEHACHAPI WIND GENERATION
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Page 7

a:2010hs-FullWind-Midway-Vincent-dlo-SPS.chf
b:2010hs-LoWind-Midway-Vincent-dlo-SPS.chf
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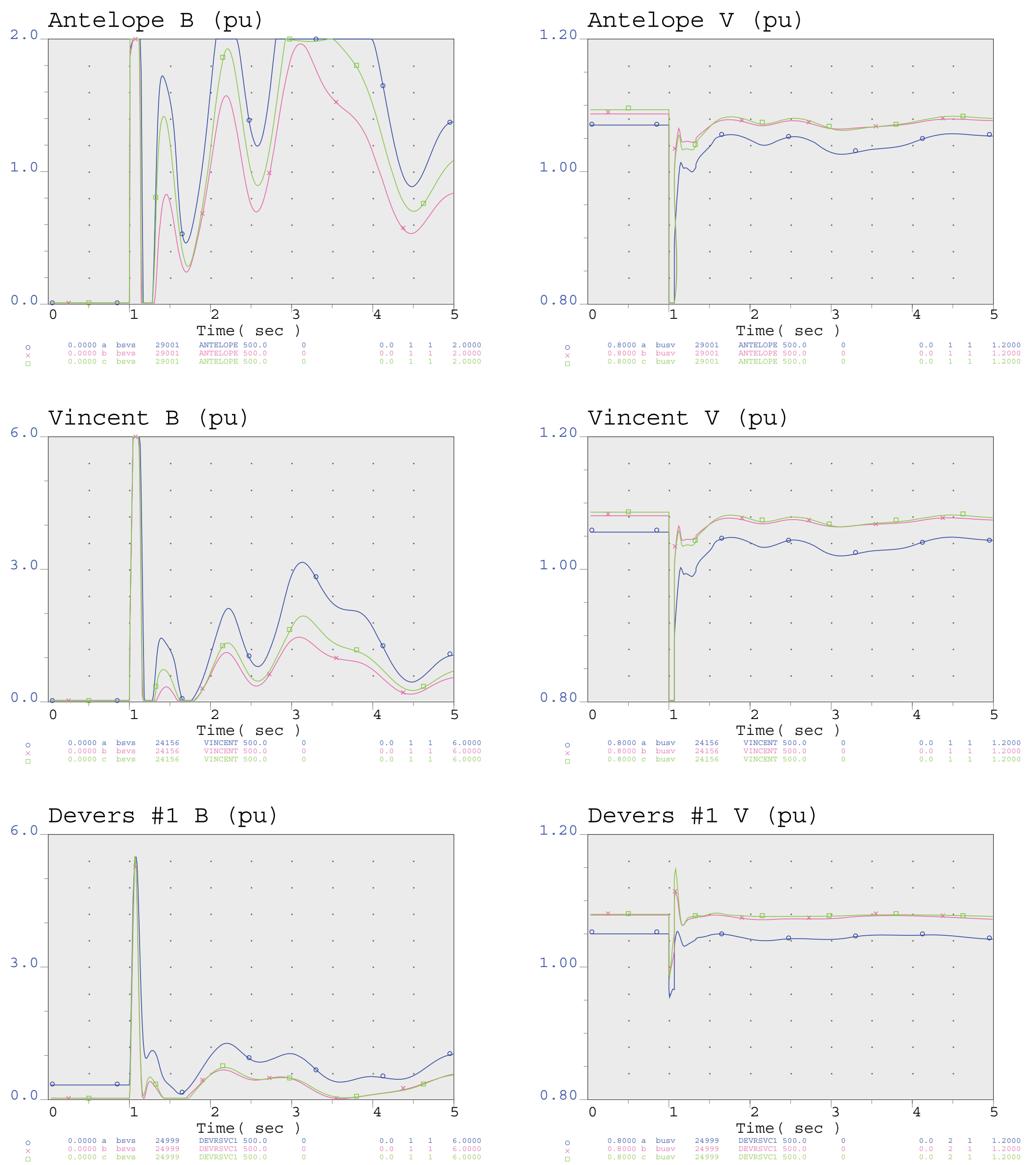
Wed Aug 22 11:21:15 2007

SVC Variables
Full Wind, Lo Wind, No Wind for Fault: 2010hs-Midway-Vincent-dlo-SPS



2010 HEAVY SUMMER POWER FLOW CASE
SUNRISE + TEHACHAPI PROJECTS - JULY 3, 2007
CAISO & GE COLLABORATIVE WIND STUDY
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Page 8

a:2010hs-FullWind-Midway-Vincent-dlo-SPS.chf
b:2010hs-LoWind-Midway-Vincent-dlo-SPS.chf
c:2010hs-NoWind-Midway-Vincent-dlo-SPS.chf

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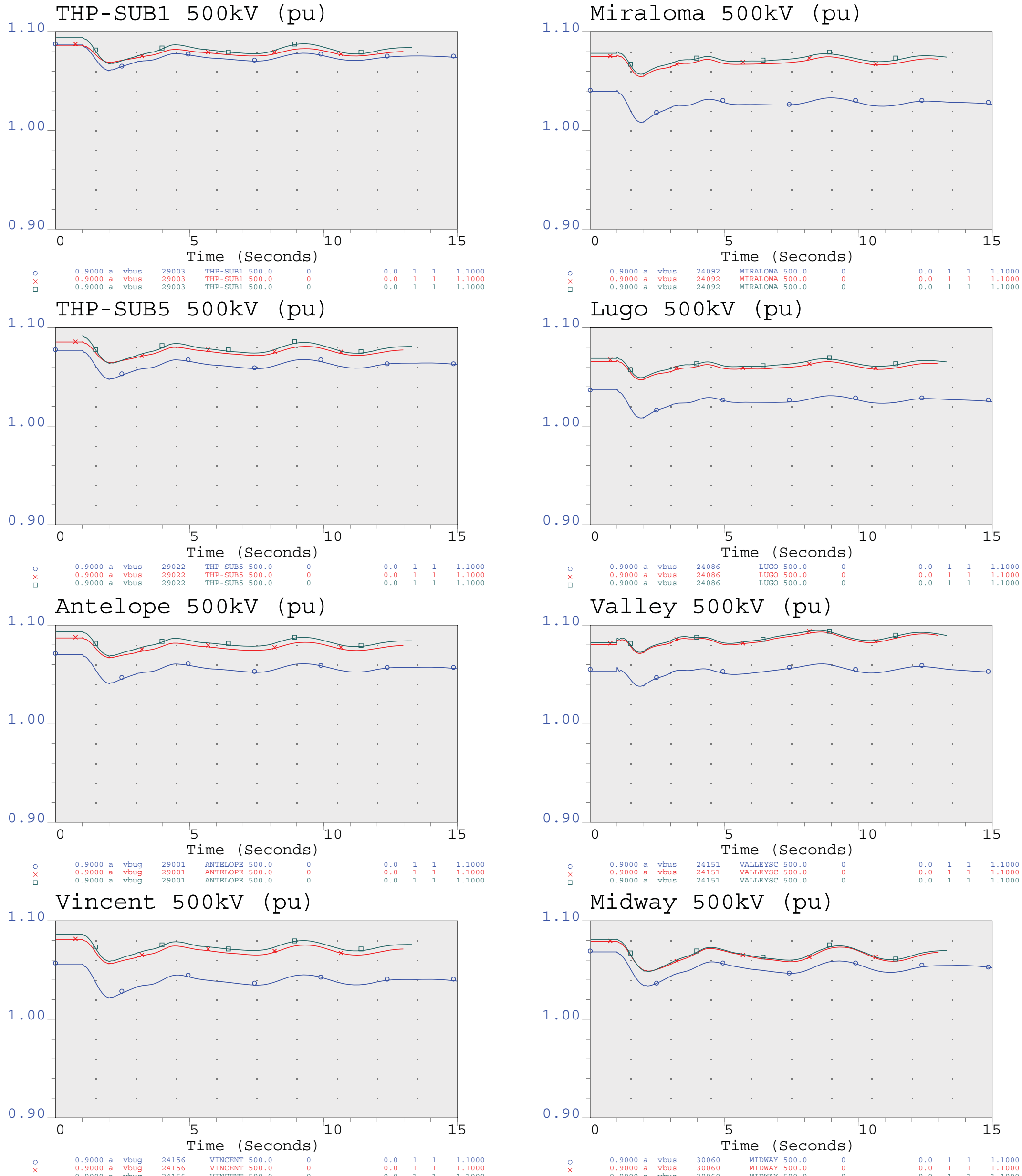
Wed Aug 22 11:21:15 2007

500kV Voltages
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PaloVerde-g2-svc



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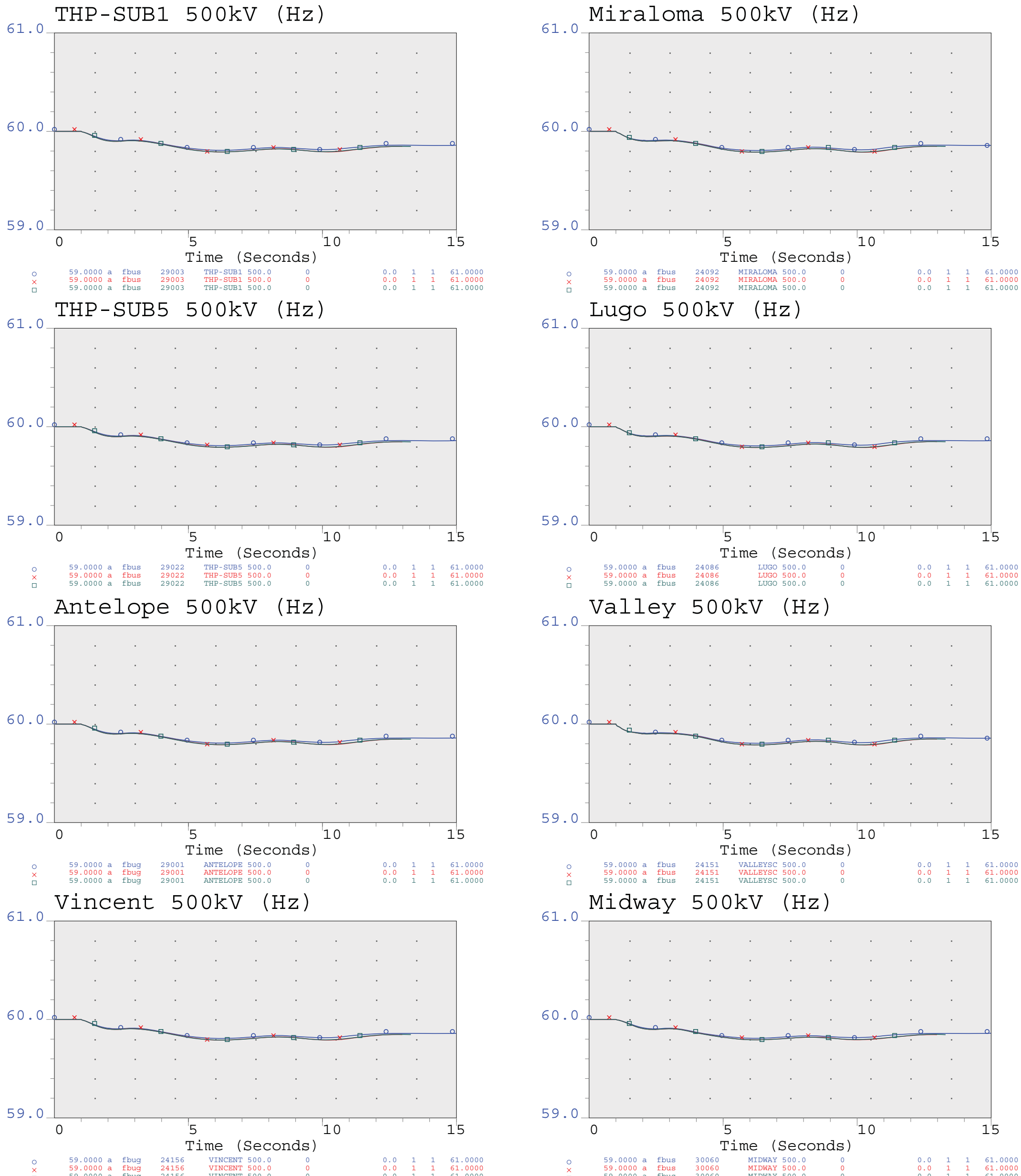
Wed Aug 22 11:15:41 2007

500kV Frequencies
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PaloVerde-g2-svc



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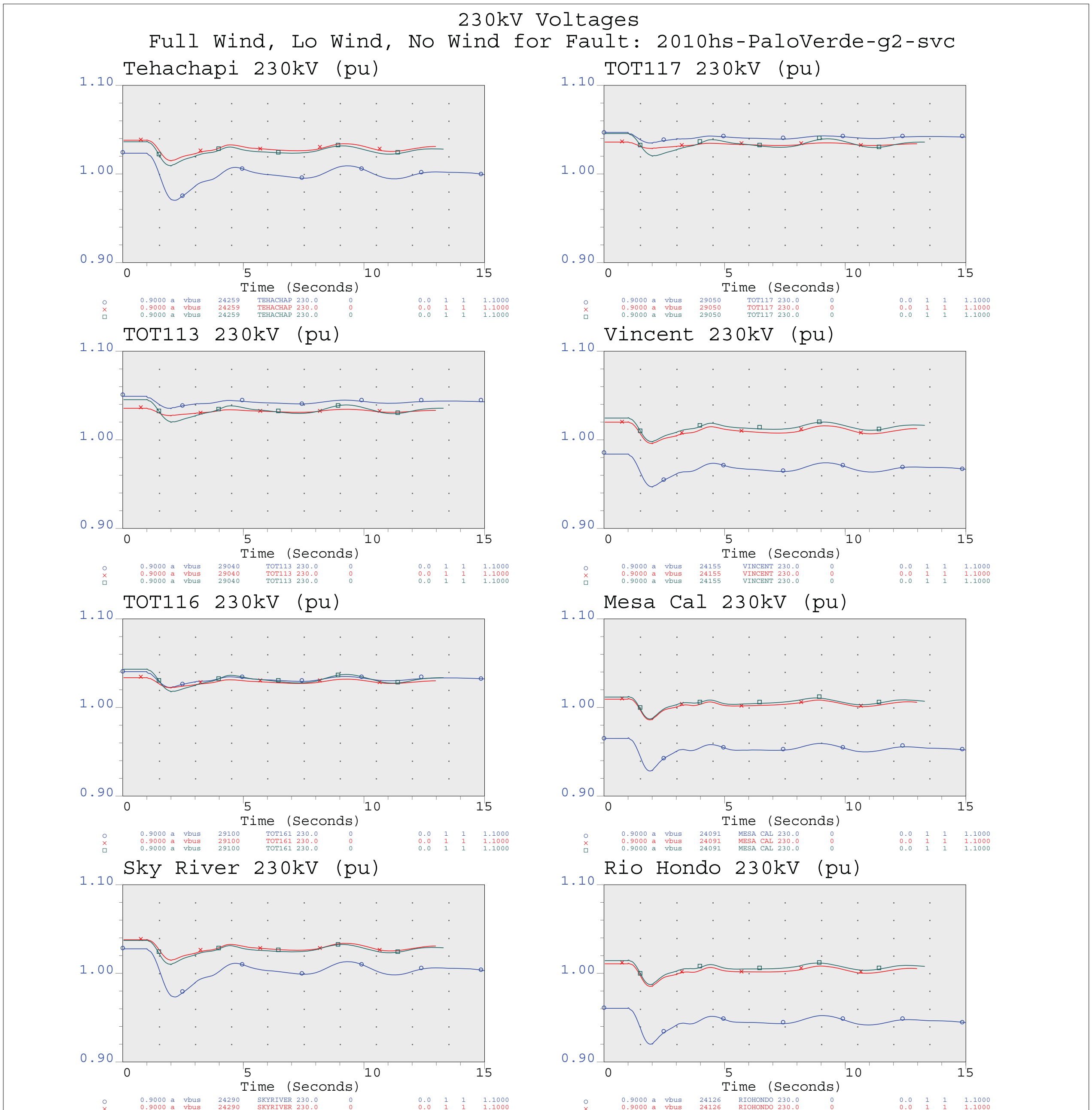

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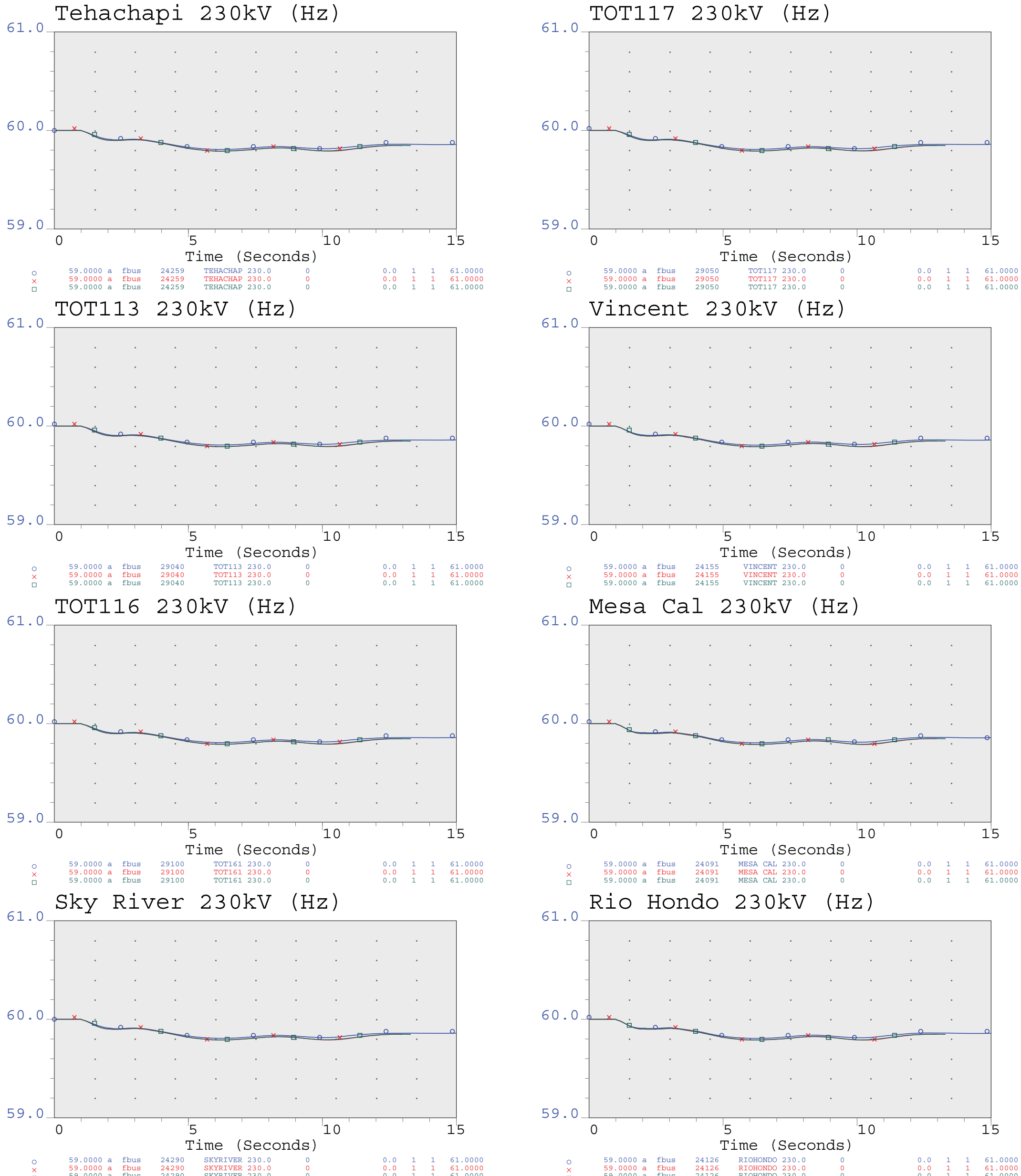
Wed Aug 22 11:15:41 2007

230kV Frequencies
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PaloVerde-g2-svc



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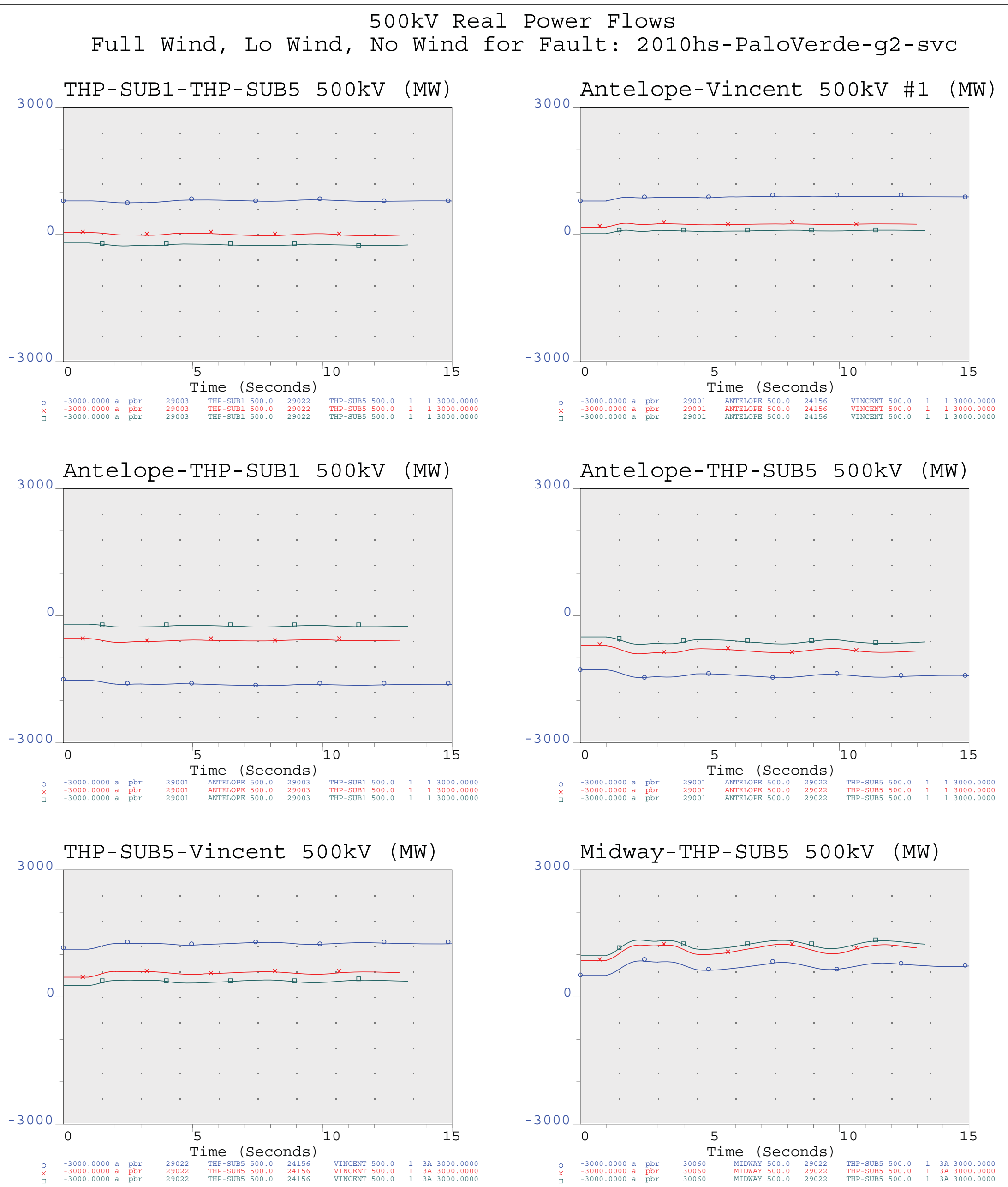

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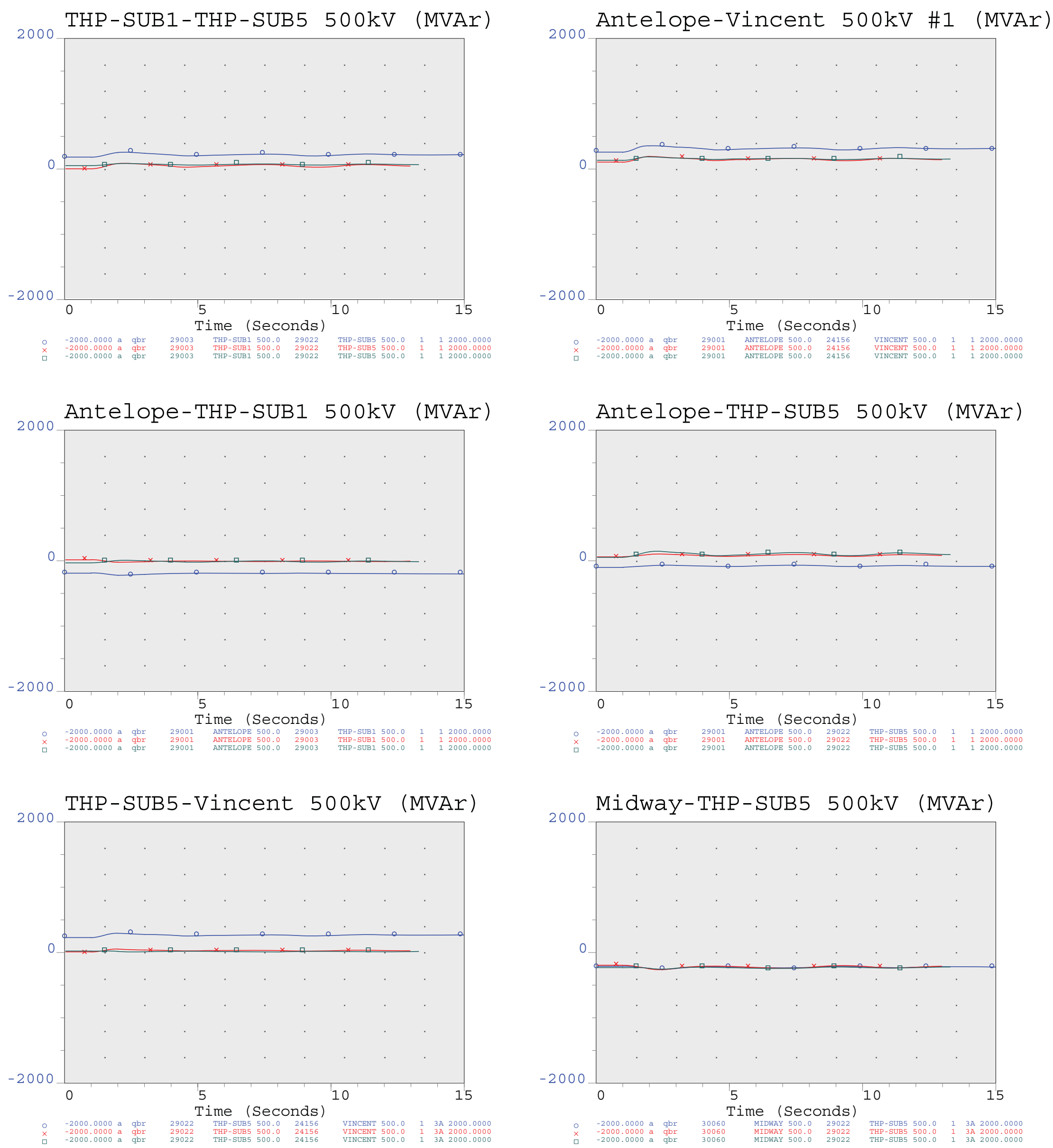
500kV Reactive Power Flows
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PaloVerde-g2-svc



Page 6

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c:2010hs-NoWind-PaloVerde-g2-svc.chf

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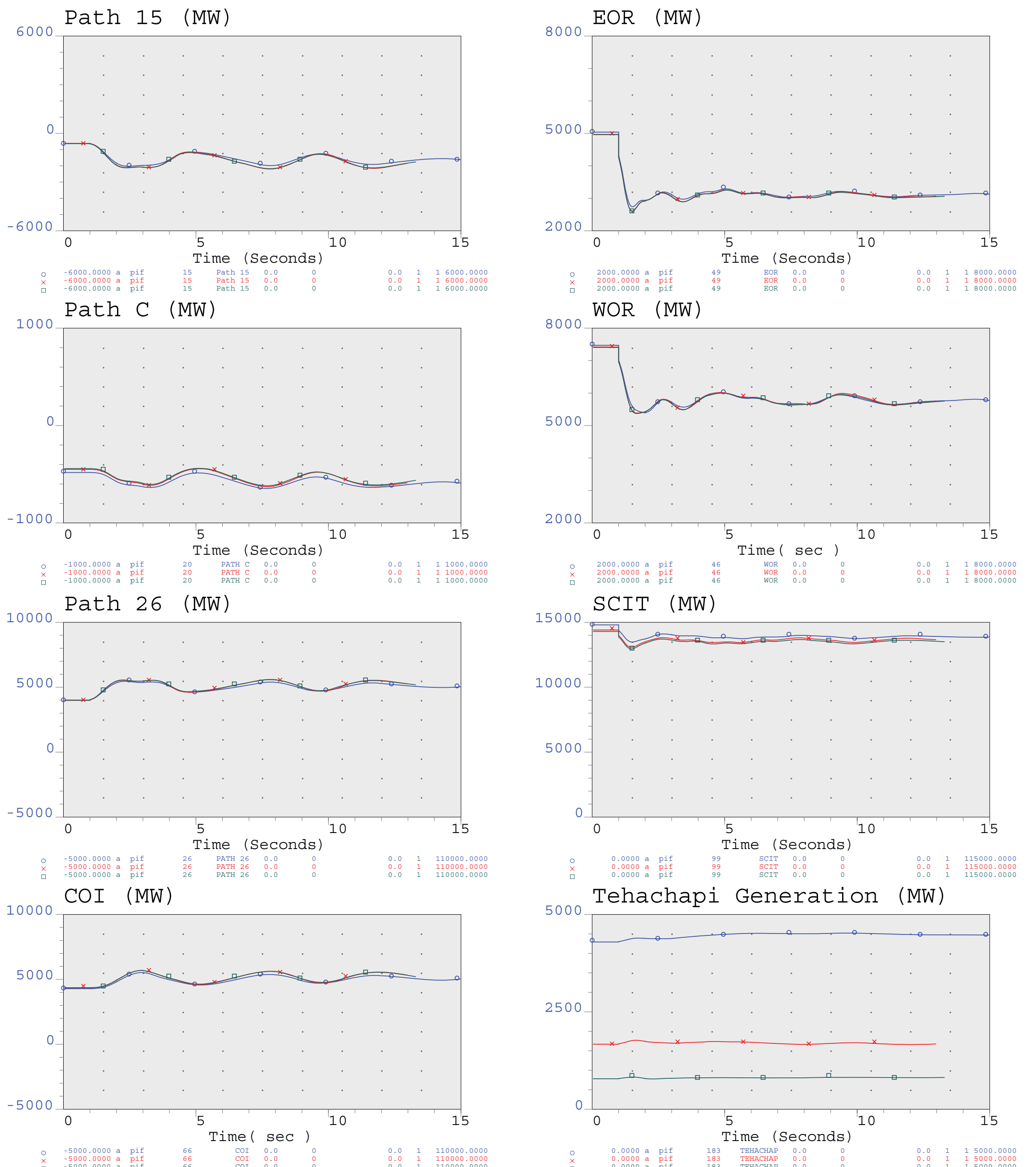
Wed Aug 22 11:15:42 2007

Interface Power Flows
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PaloVerde-g2-svc



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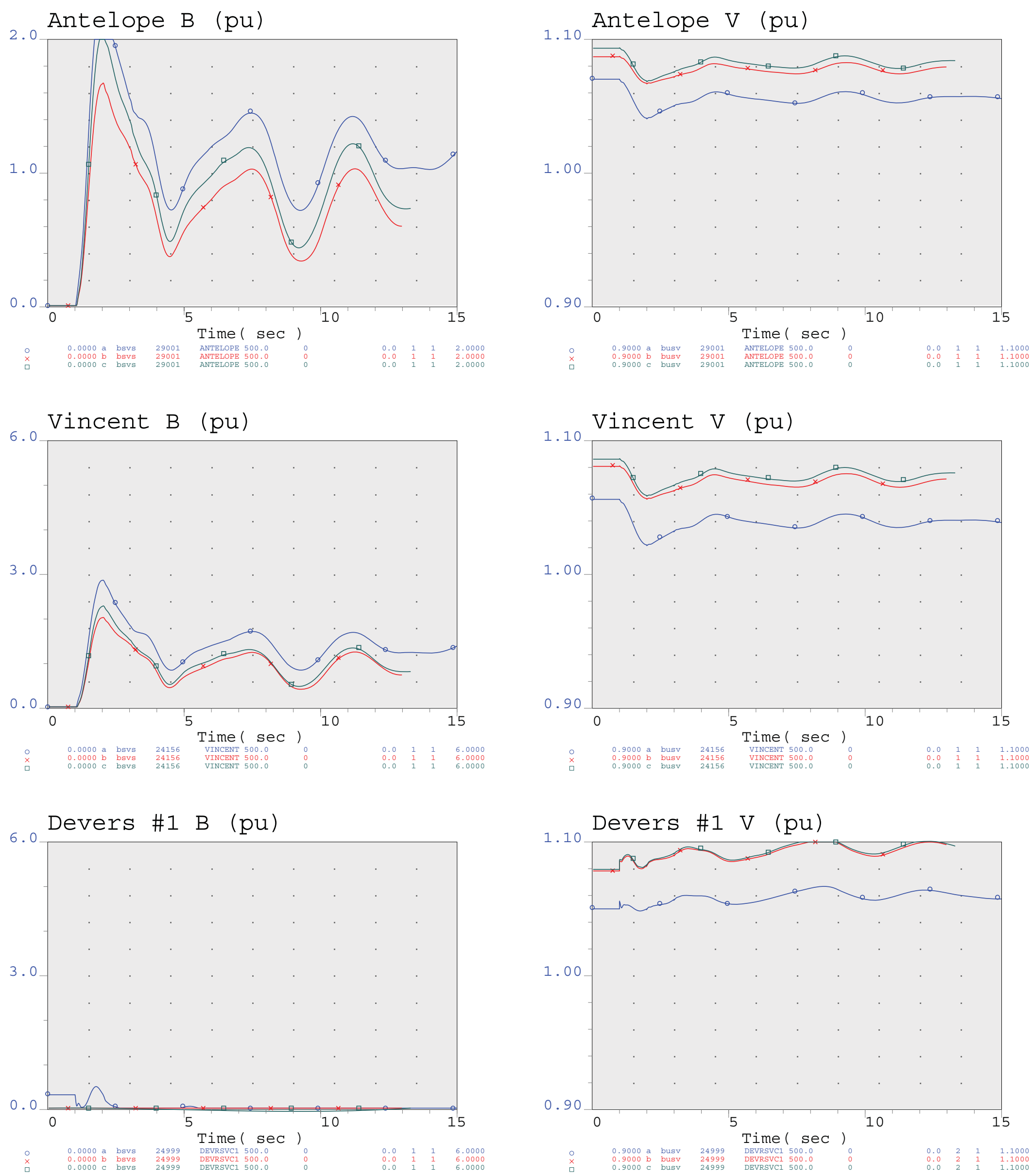
SVC Variables
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PaloVerde-g2-svc



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c:2010hs-NoWind-PaloVerde-g2-svc.chf

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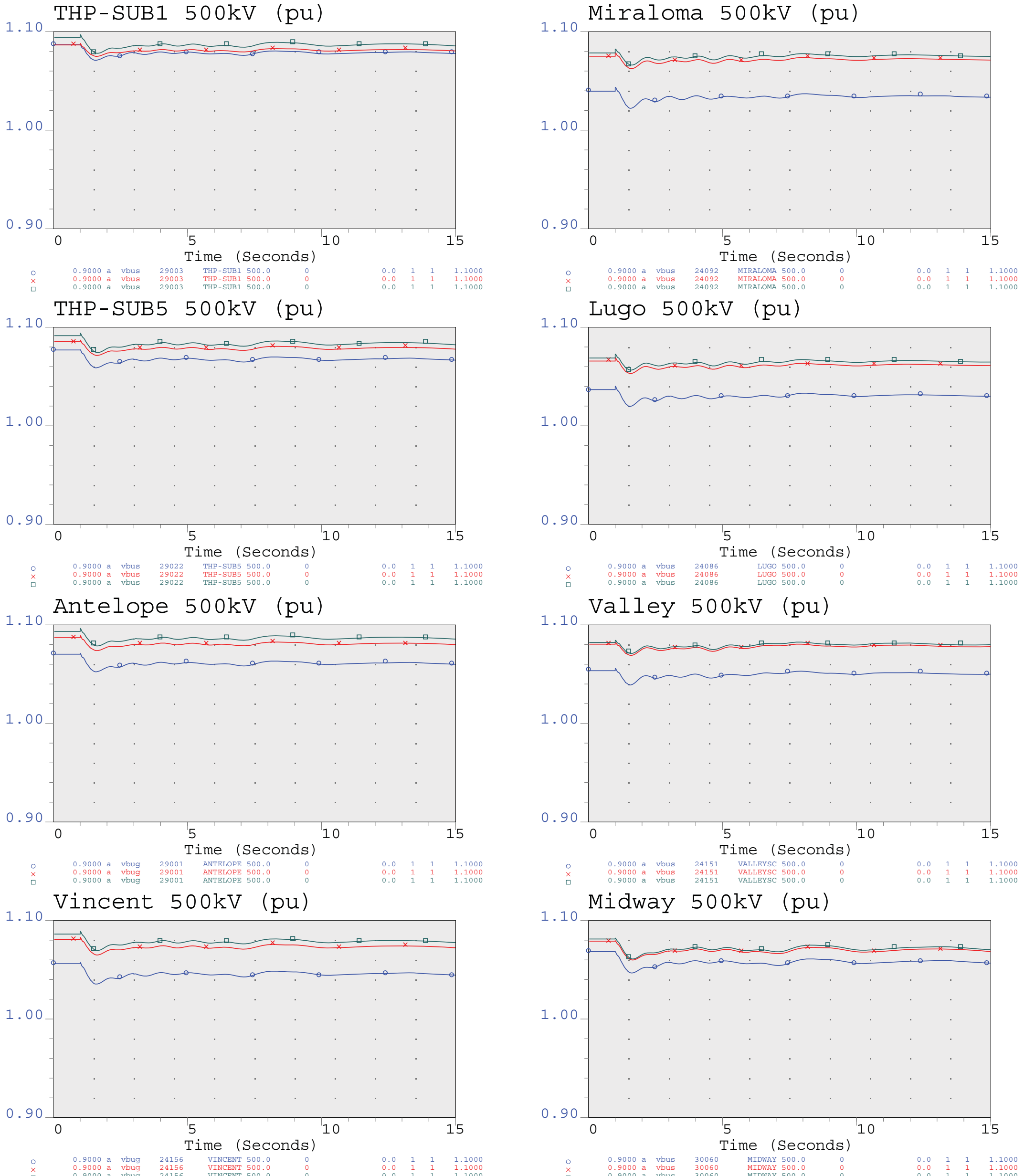
Wed Aug 22 11:15:42 2007

500kV Voltages

Full Wind, Lo Wind, No Wind for Fault: 2010hs-PDCI-NS-bipole-2000-svc



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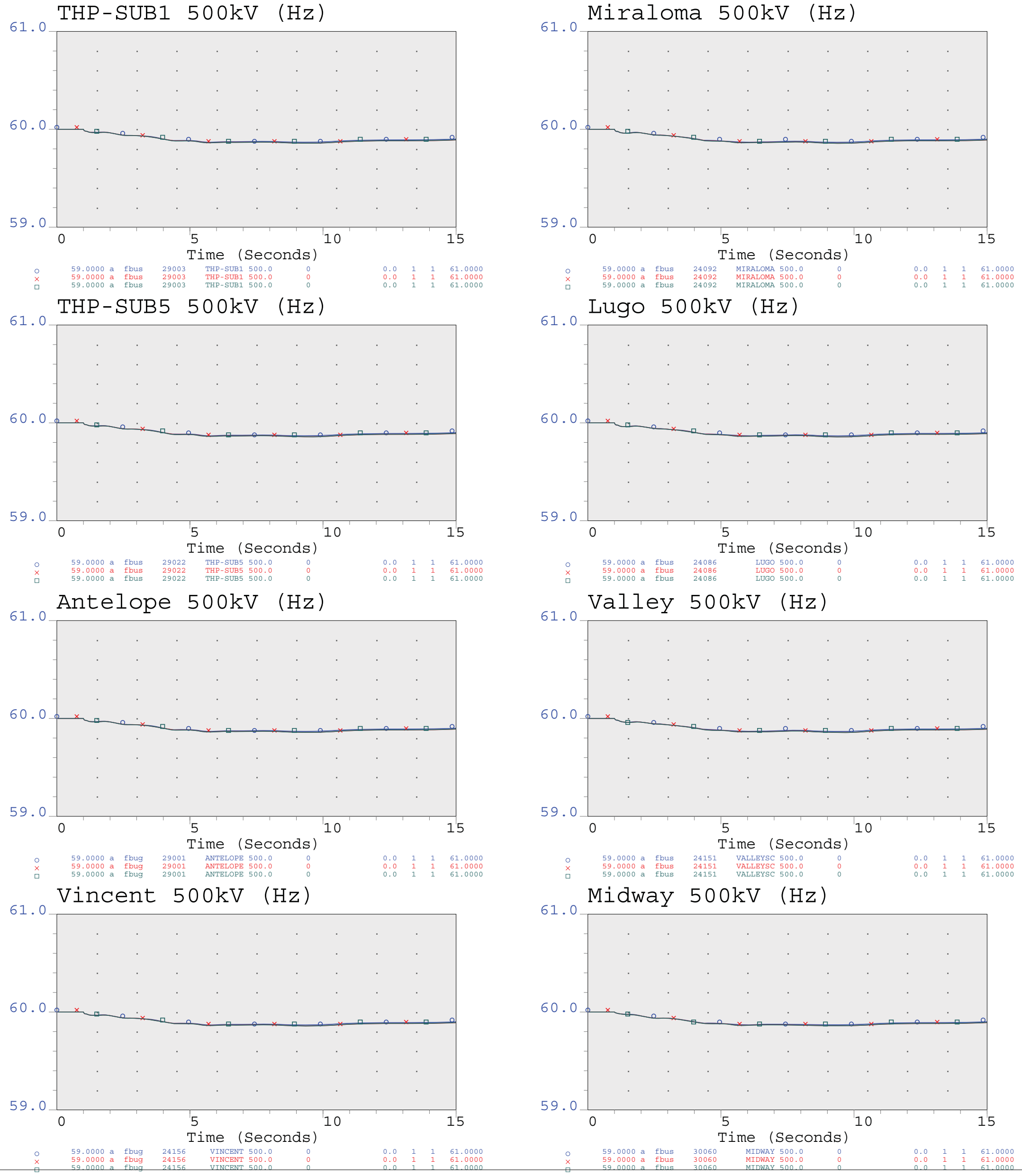
500kV Frequencies
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PDCI-NS-bipole-2000-svc



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c:2010hs-NoWind-PDCI-NS-bipole-2000-svc.chf

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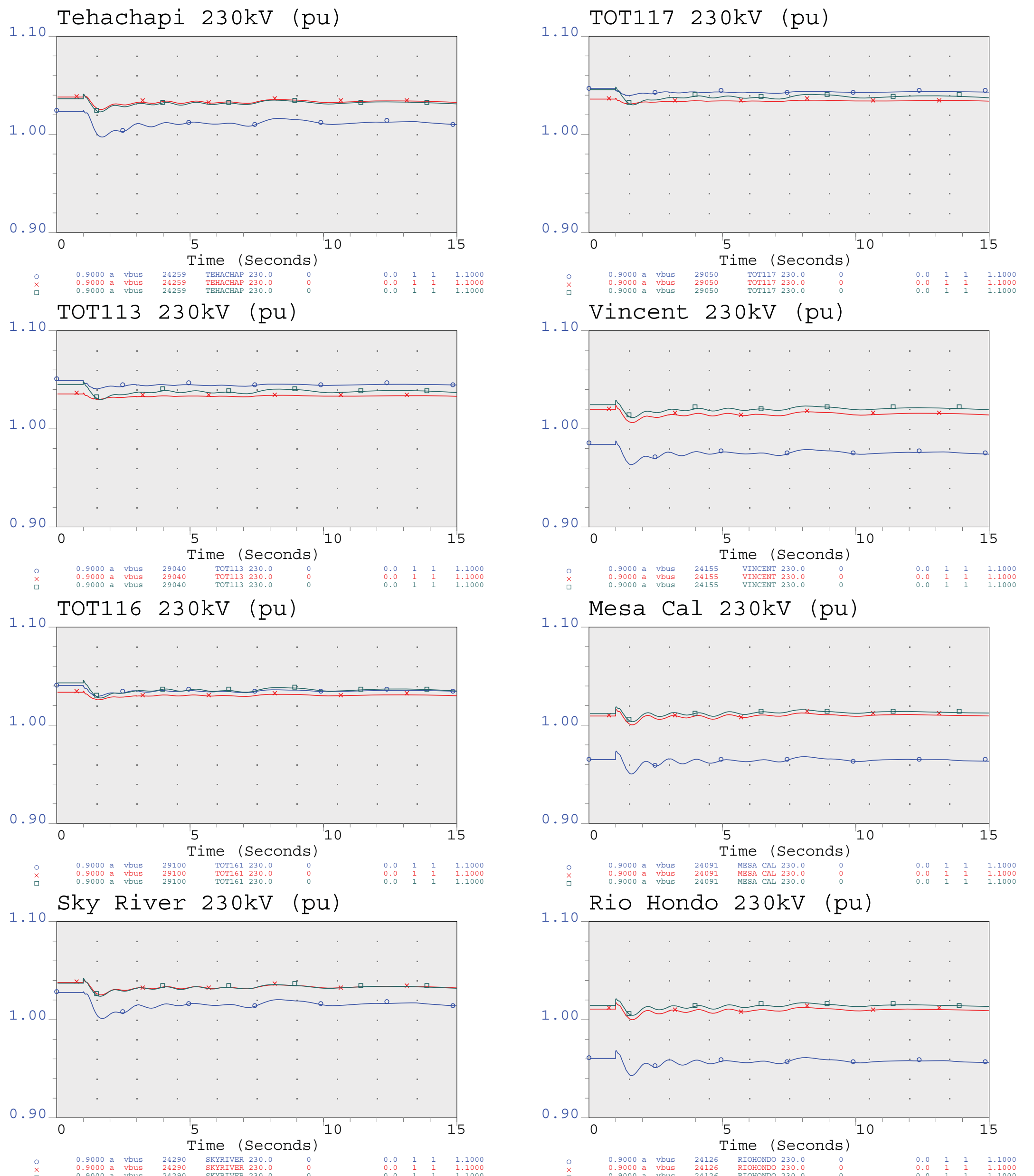
Wed Aug 22 11:16:07 2007

230kV Voltages

Full Wind, Lo Wind, No Wind for Fault: 2010hs-PDCI-NS-bipole-2000-svc



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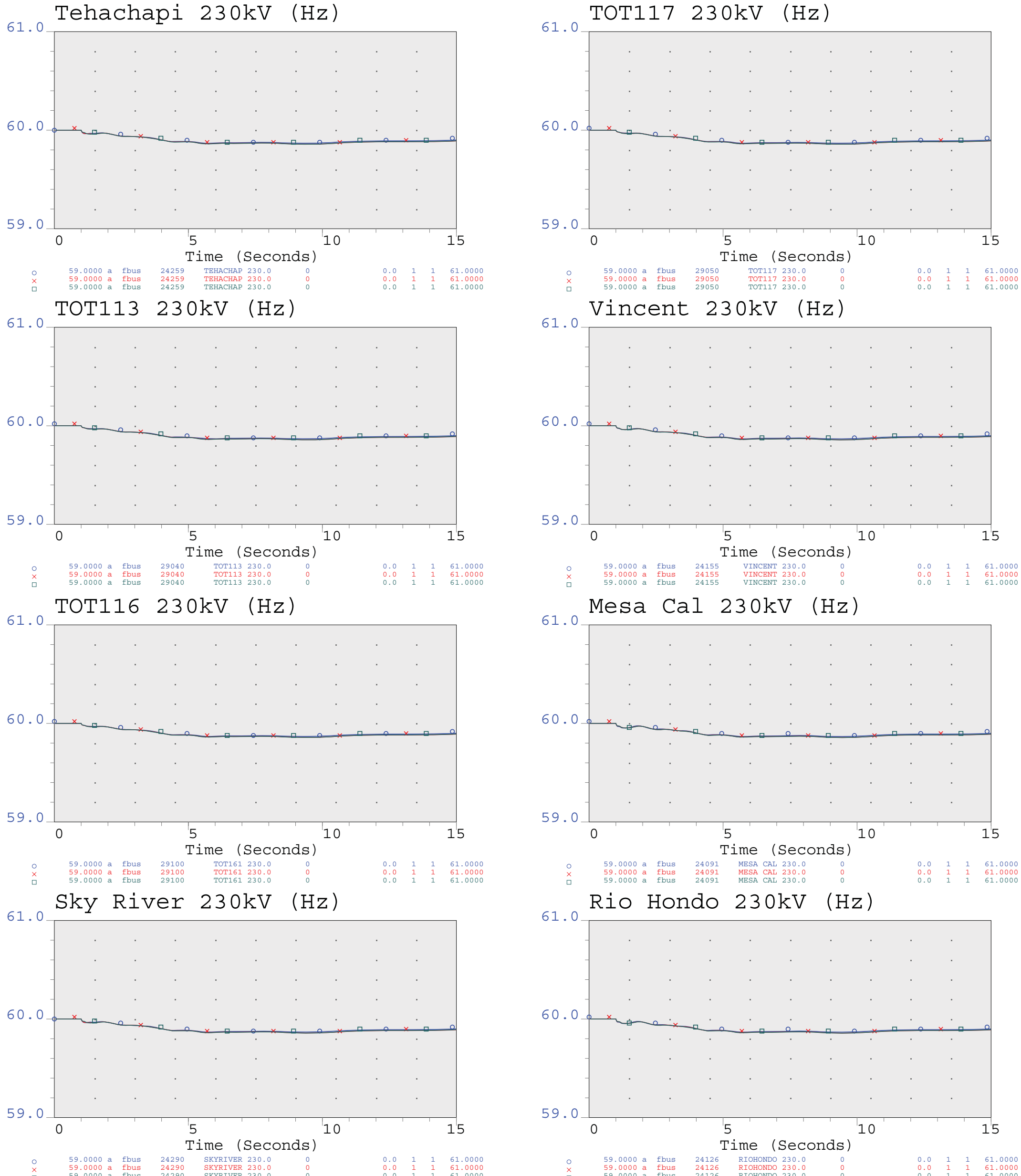
230kV Frequencies
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PDCI-NS-bipole-2000-svc



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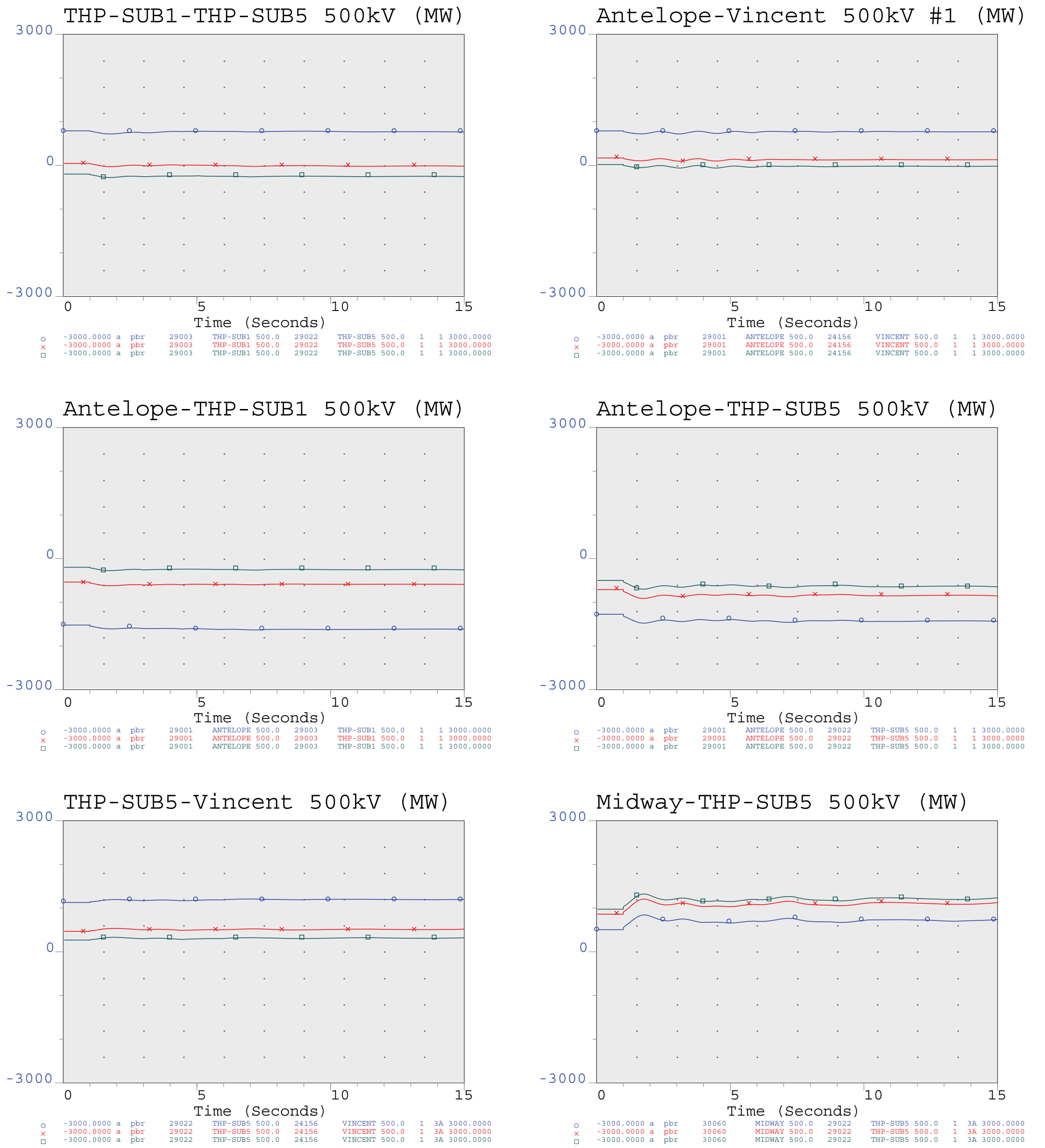
Wed Aug 22 11:16:08 2007

500kV Real Power Flows
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PDCI-NS-bipole-2000-svc



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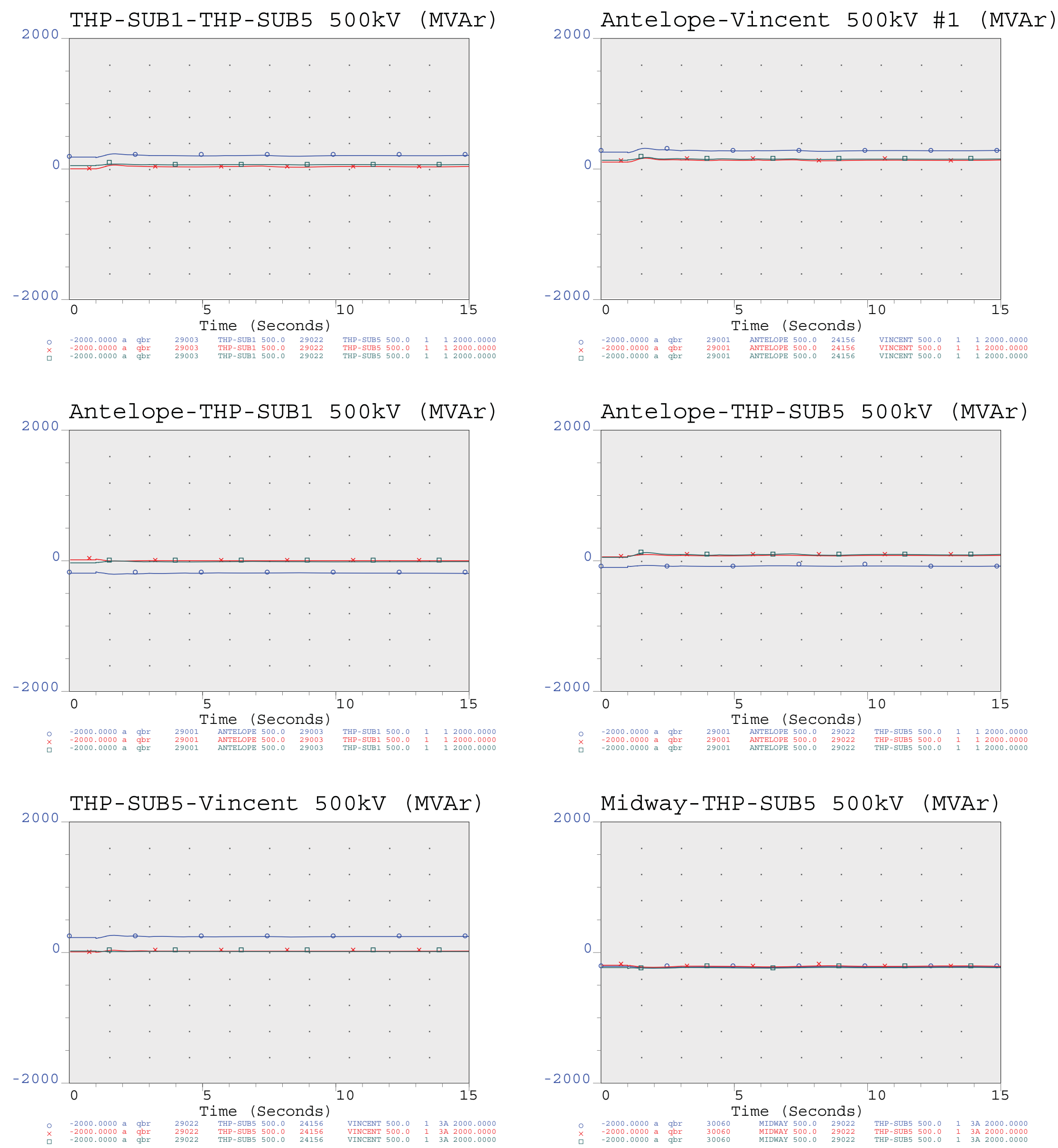
Wed Aug 22 11:16:08 2007

500kV Reactive Power Flows
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PDCI-NS-bipole-2000-svc



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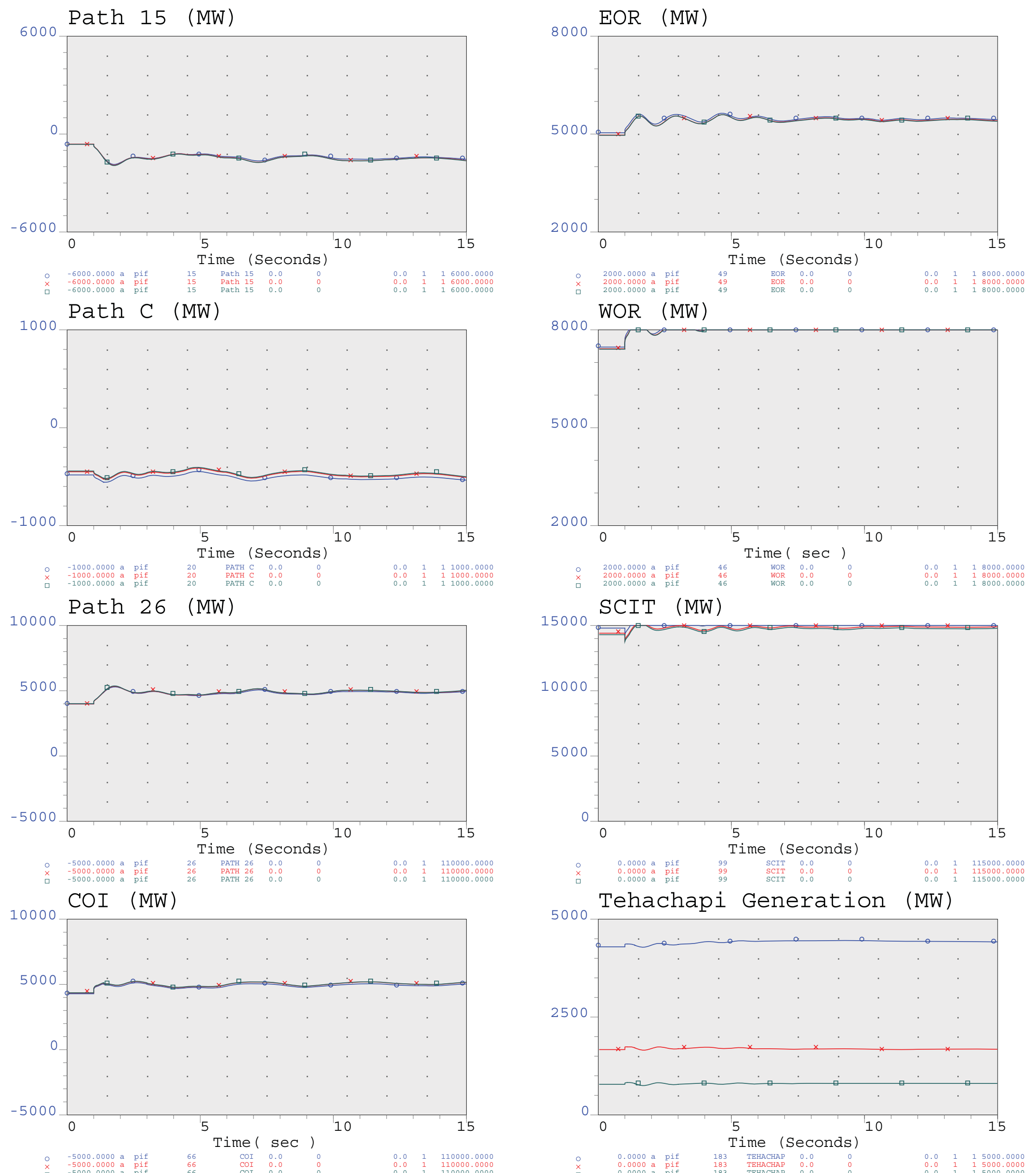
Wed Aug 22 11:16:08 2007

Interface Power Flows
Full Wind, Lo Wind, No Wind for Fault: 2010hs-PDCI-NS-bipole-2000-svc



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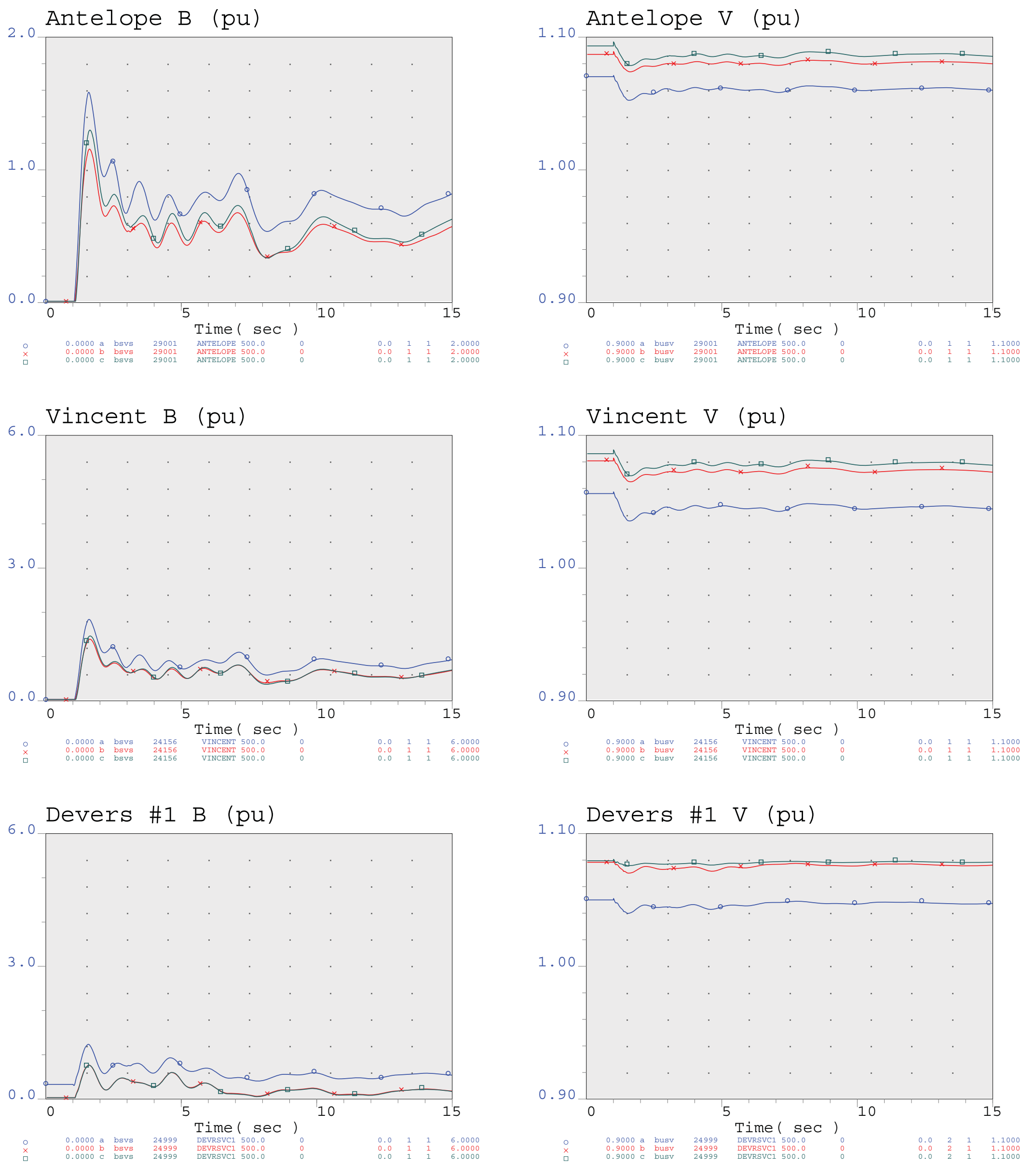
Wed Aug 22 11:16:08 2007

SVC Variables

Full Wind, Lo Wind, No Wind for Fault: 2010hs-PDCI-NS-bipole-2000-svc



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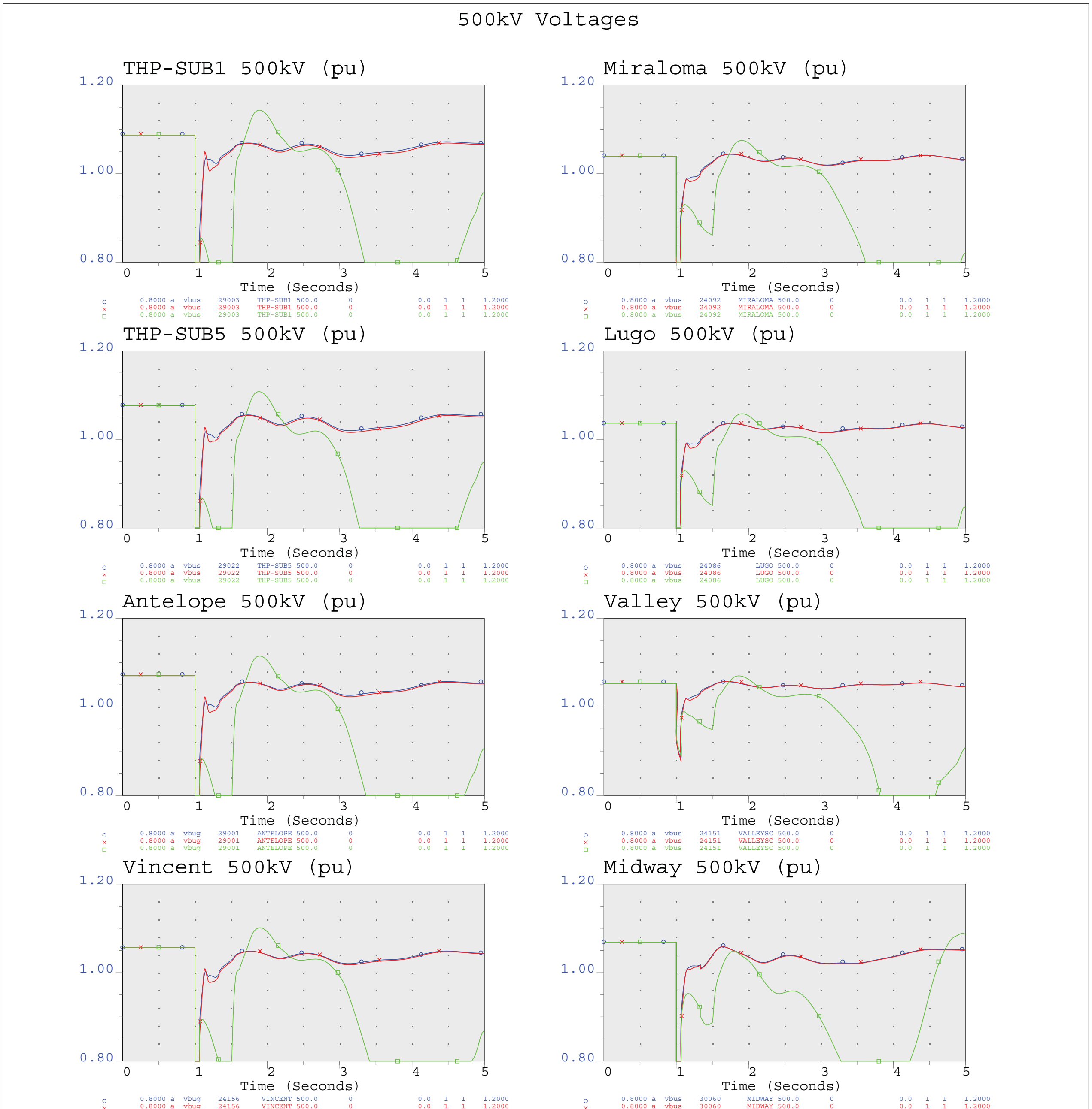

Page 1

a:2010hs-FullWind-Midway-Vincent-SPS-dlo-30-0.chf
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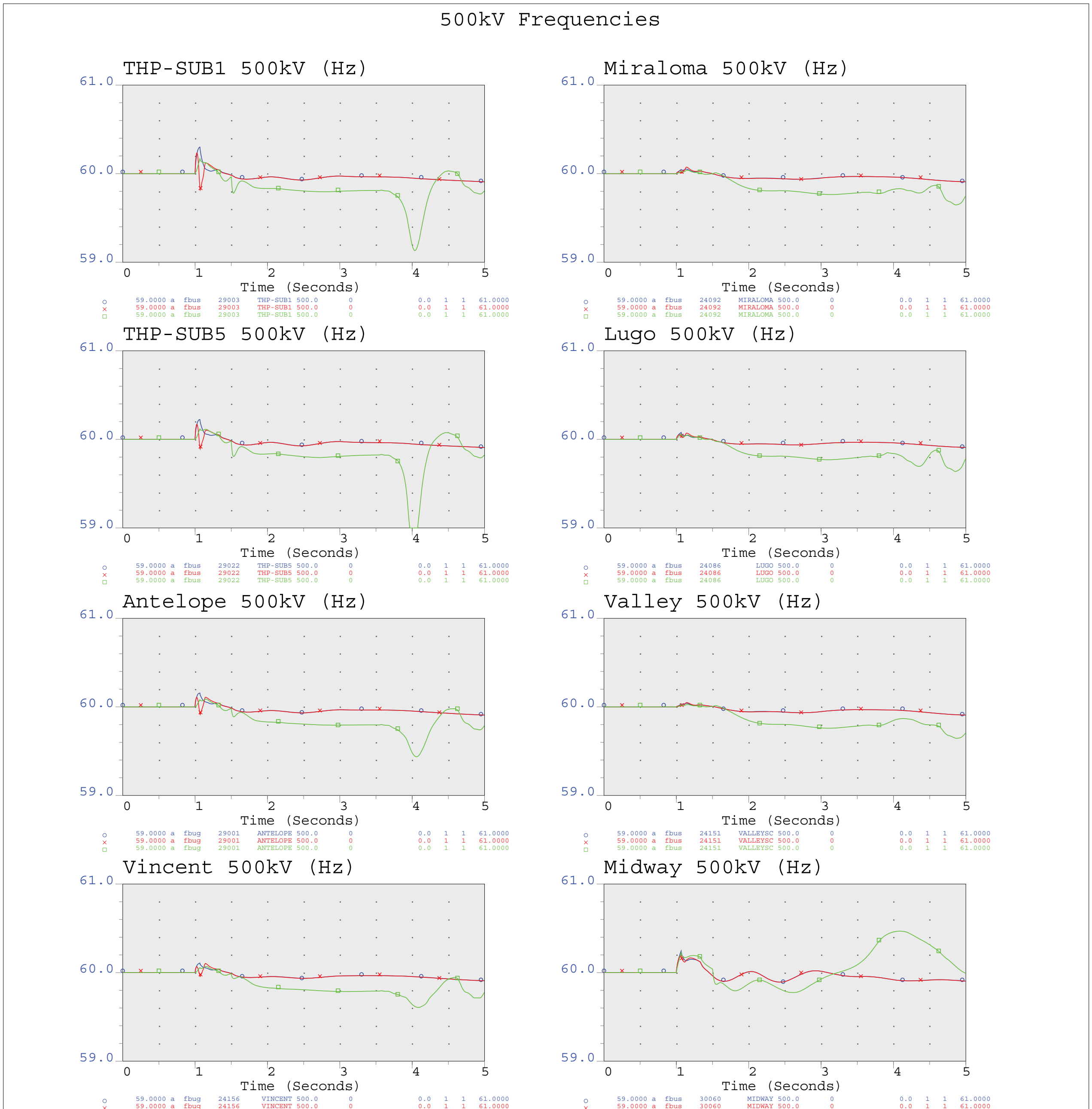
Mon Aug 20 10:27:44 2007



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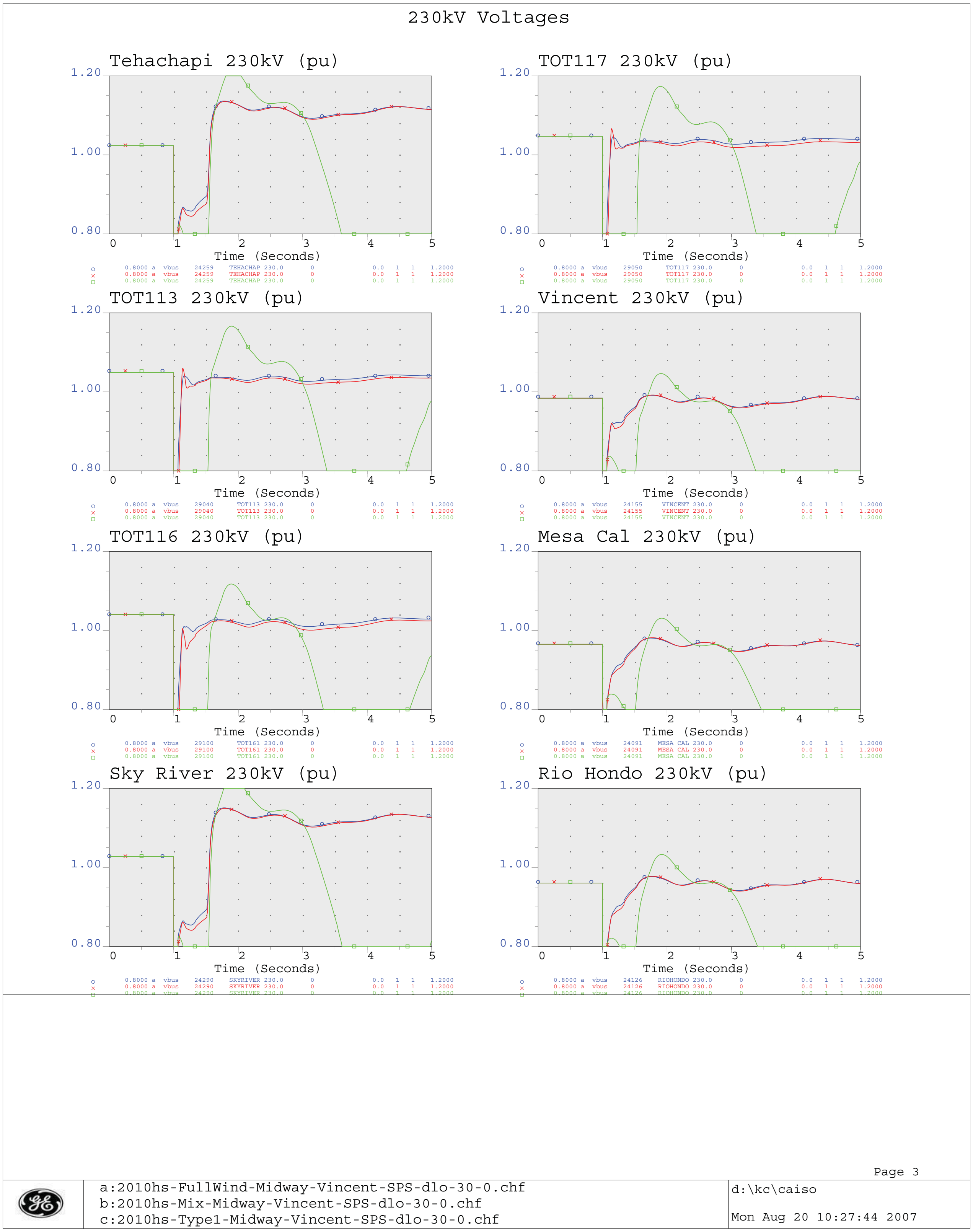
Mon Aug 20 10:27:44 2007



230kV Voltages
Tehachapi 230kV (pu)
TOT117 230kV (pu)
TOT113 230kV (pu)
Vincent 230kV (pu)
TOT116 230kV (pu)
Mesa Cal 230kV (pu)
Sky River 230kV (pu)
Rio Hondo 230kV (pu)
1.20
1.00
0.80
0
1
2
3
4
5
Time (Seconds)
Page 3
a:2010hs-FullWind-Midway-Vincent-SPS-dlo-30-0.chf
b:2010hs-Mix-Midway-Vincent-SPS-dlo-30-0.chf
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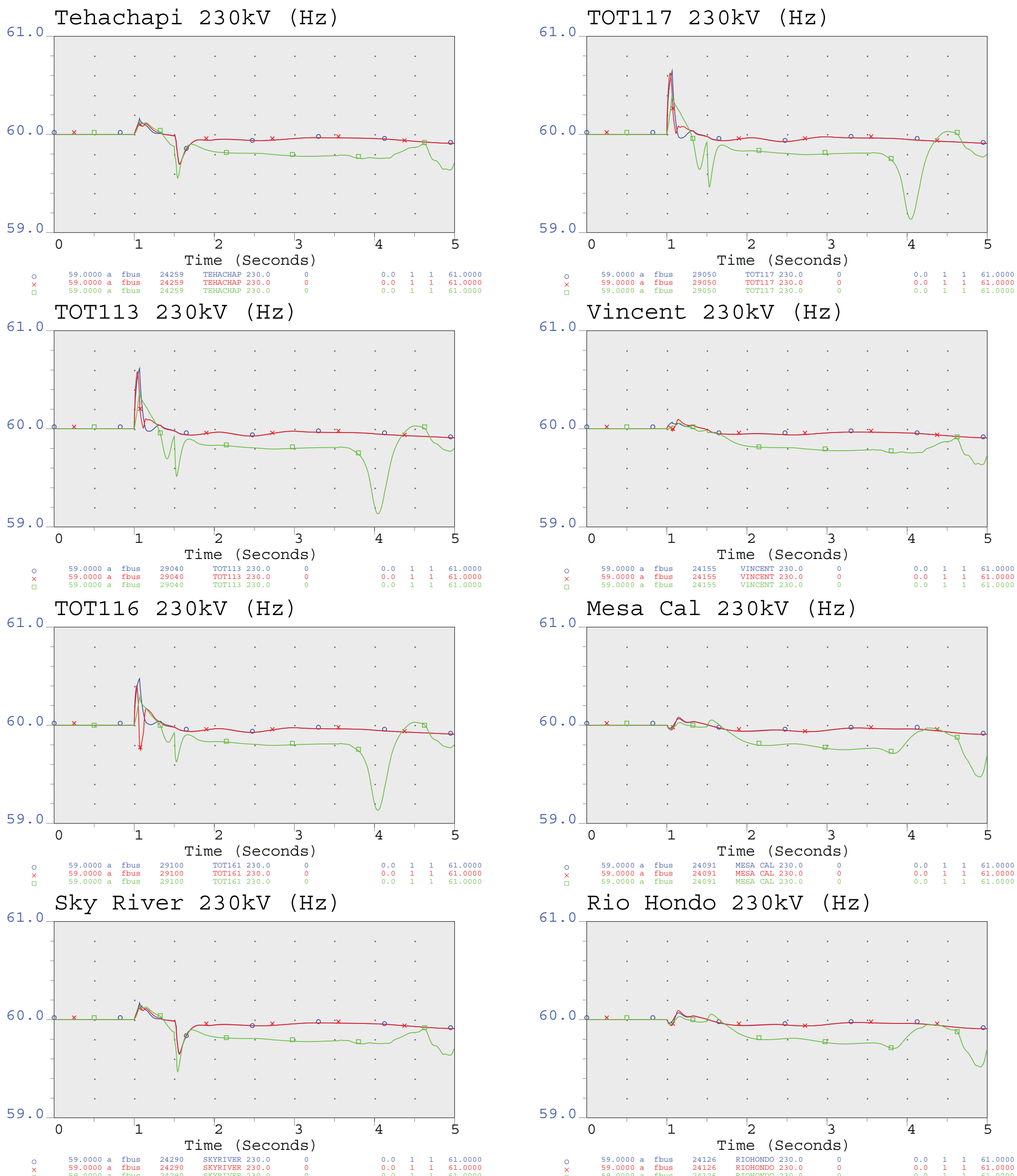
Mon Aug 20 10:27:44 2007

230kV Frequencies



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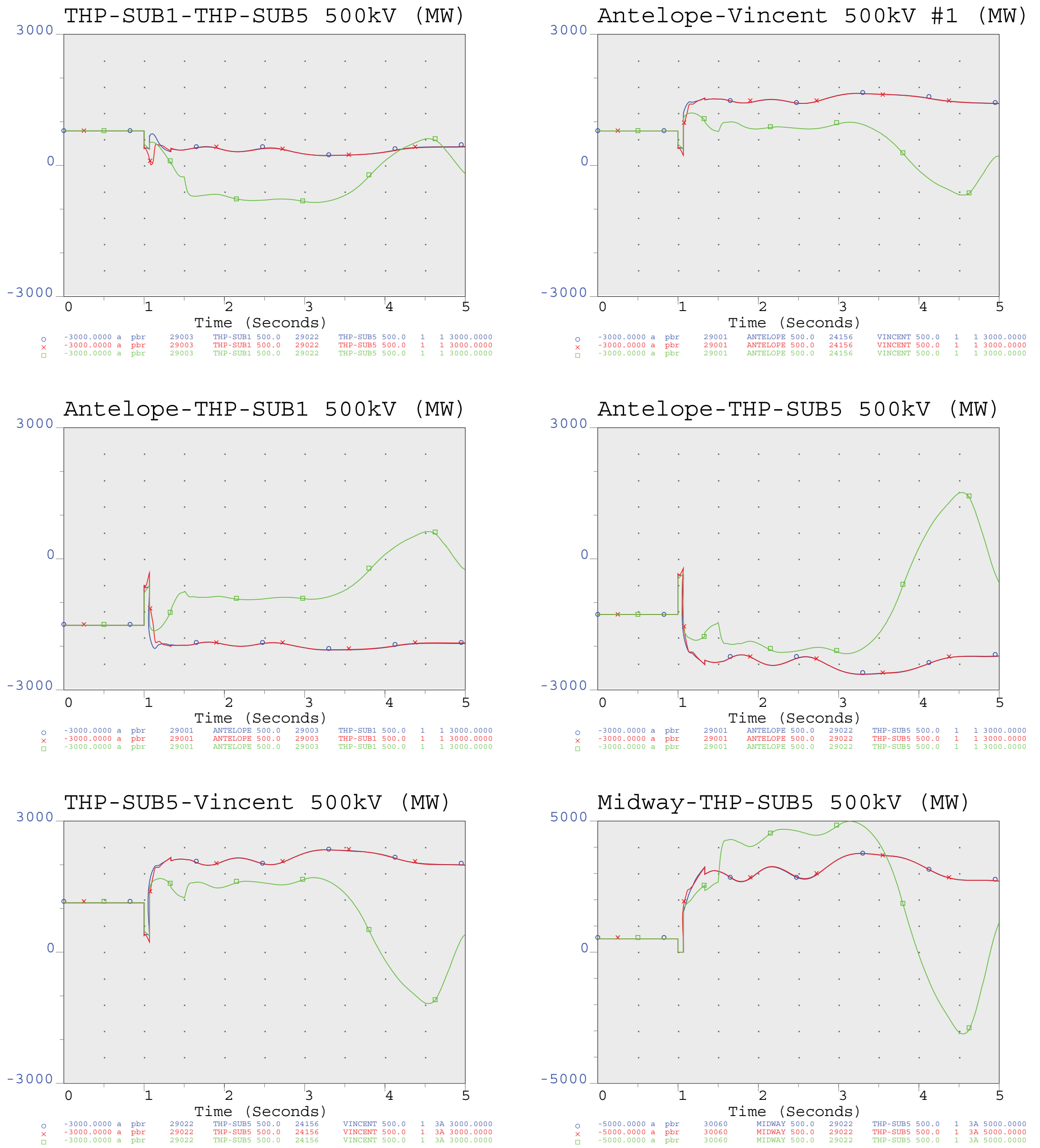
500kV Real Power Flows



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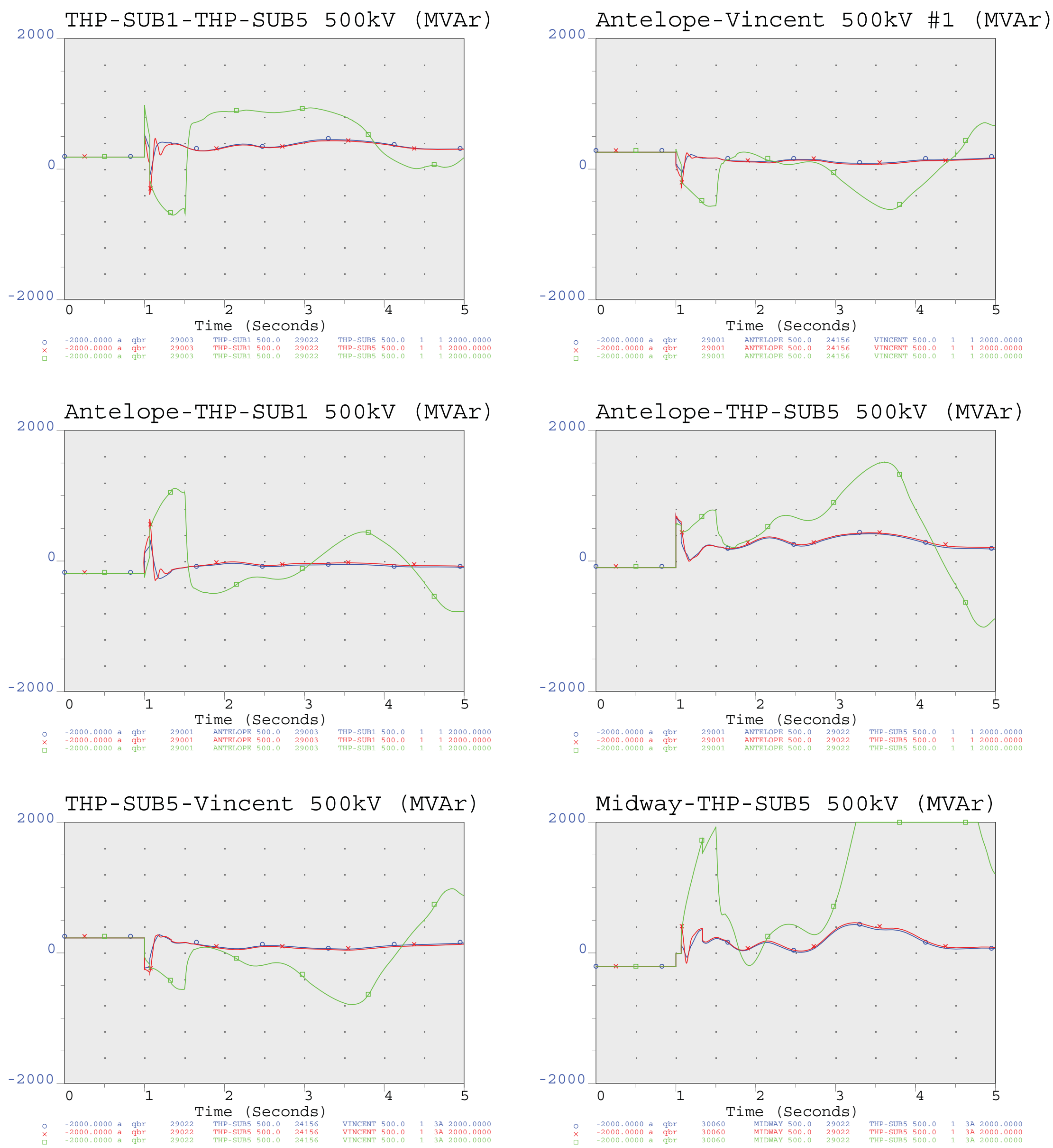
500kV Reactive Power Flows



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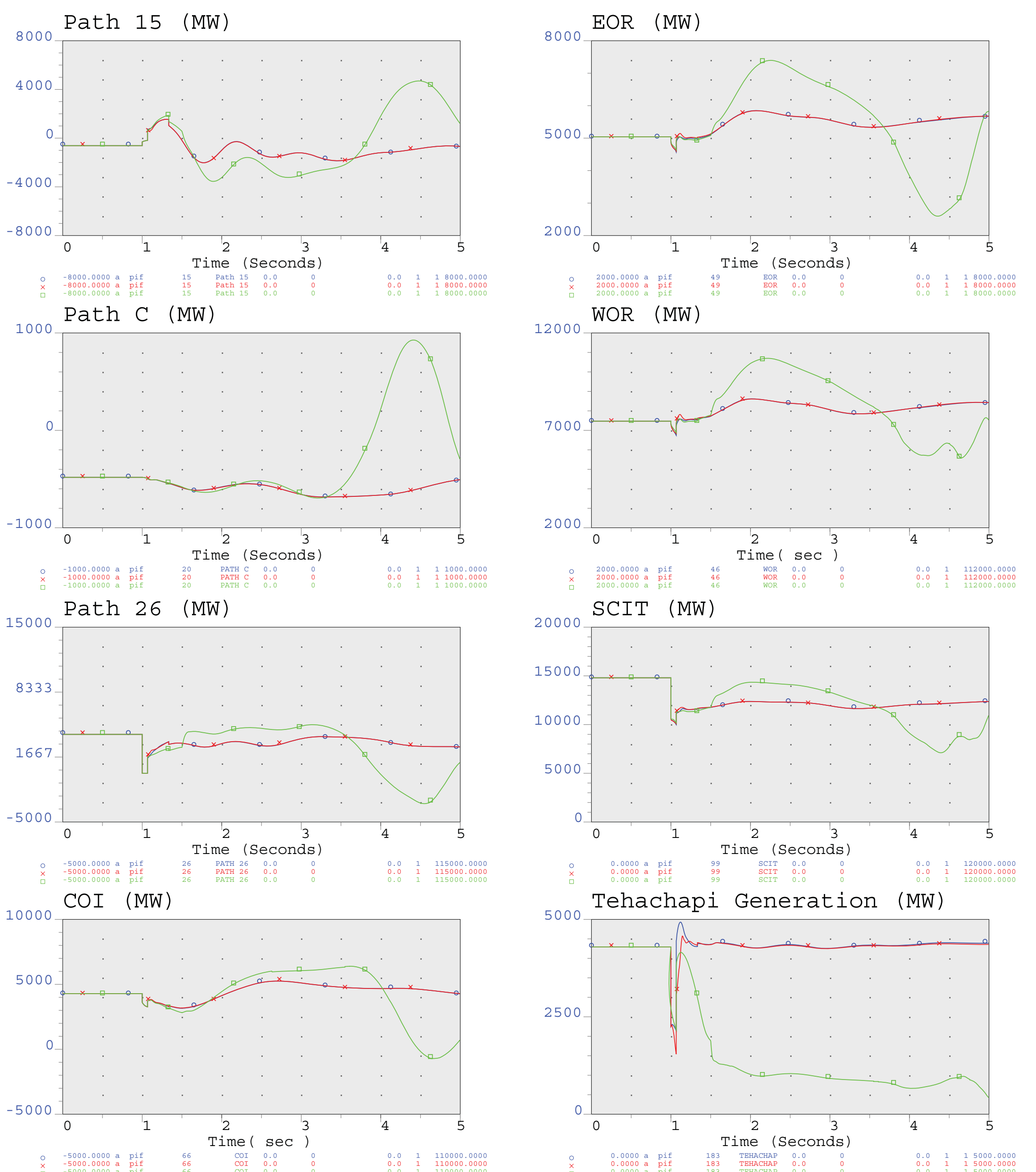
Interface Power Flows



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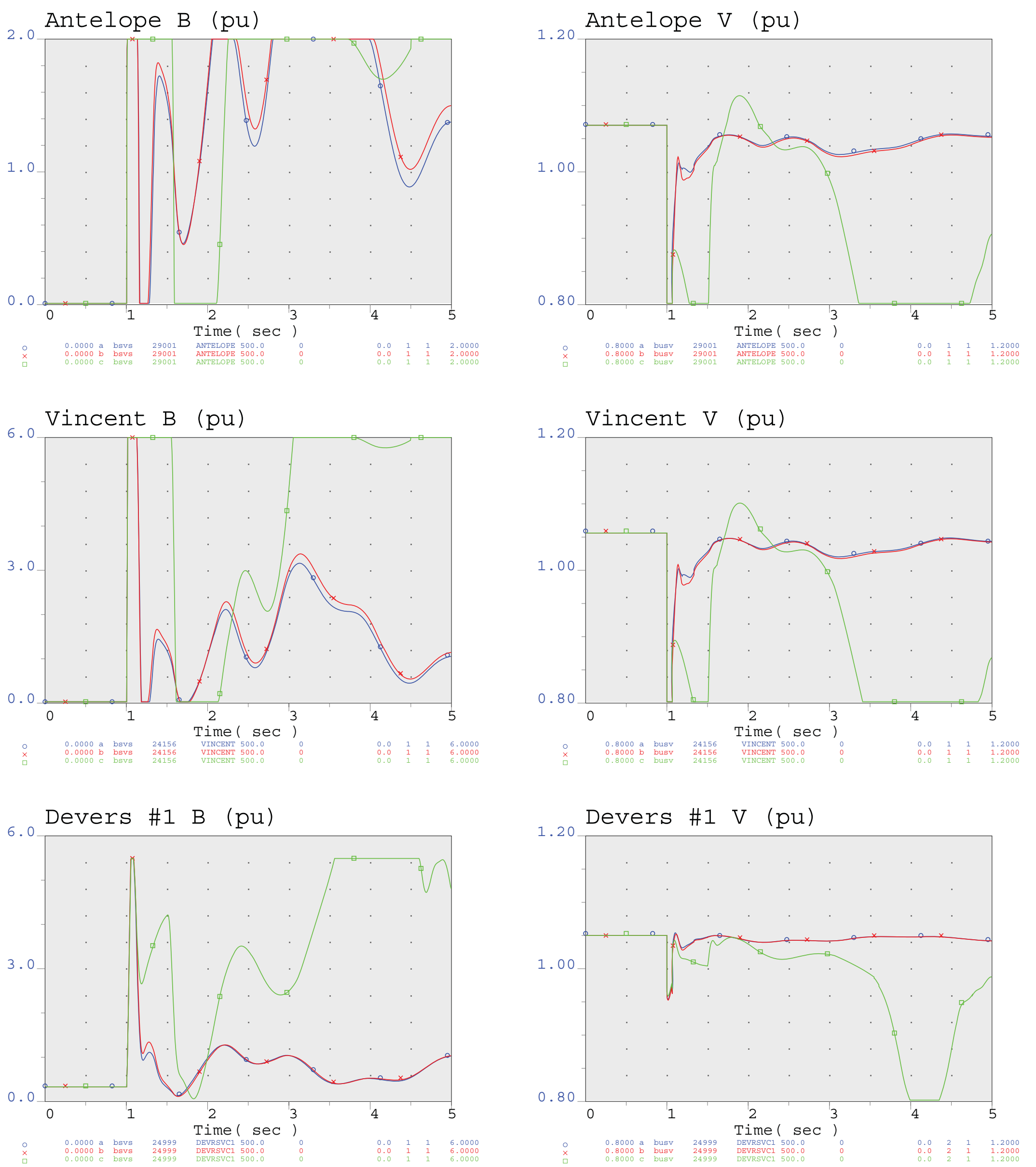
Mon Aug 20 10:27:45 2007

SVC Variables



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c:2010hs-Type1-Midway-Vincent-SPS-dlo-30-0.chf

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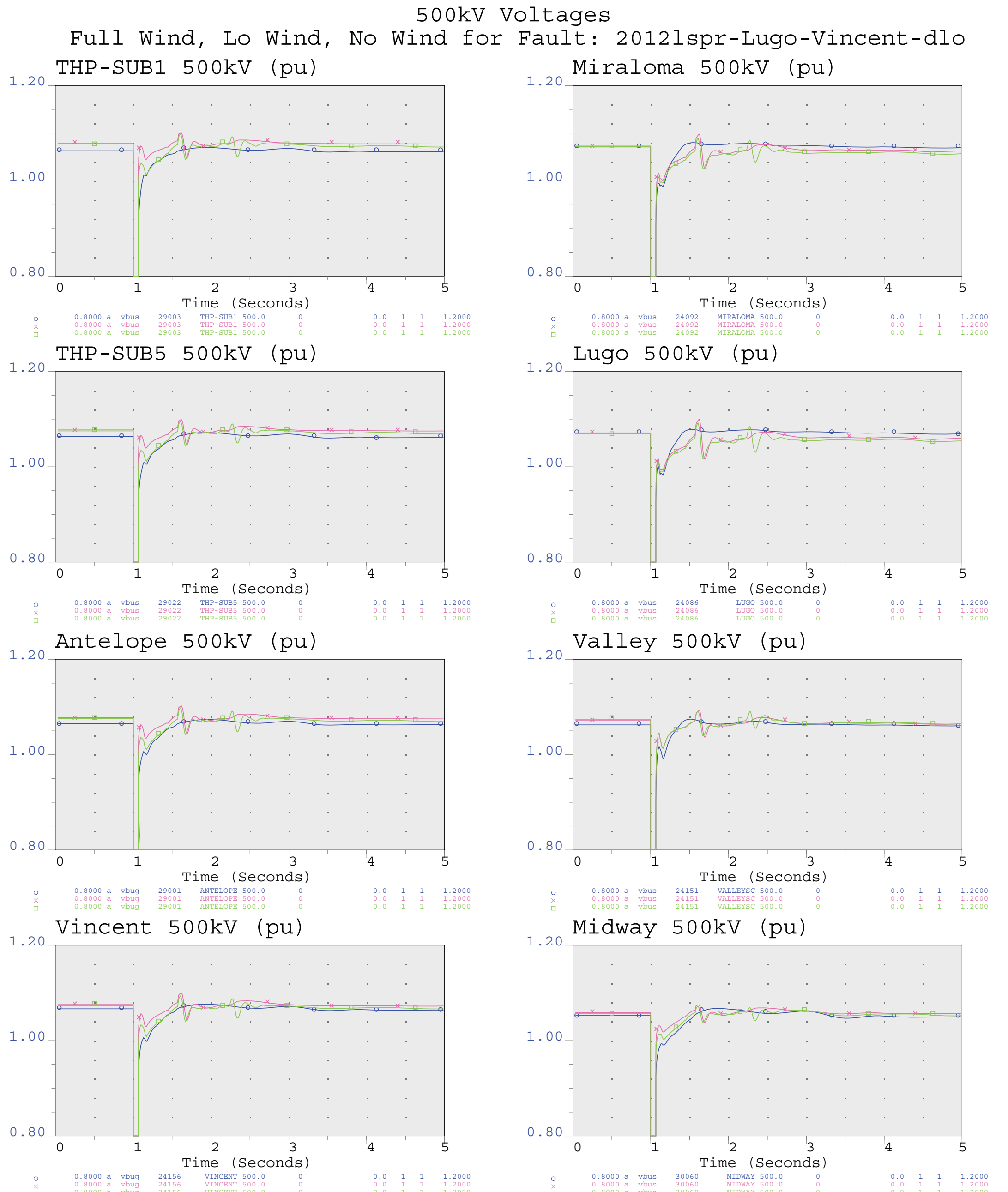

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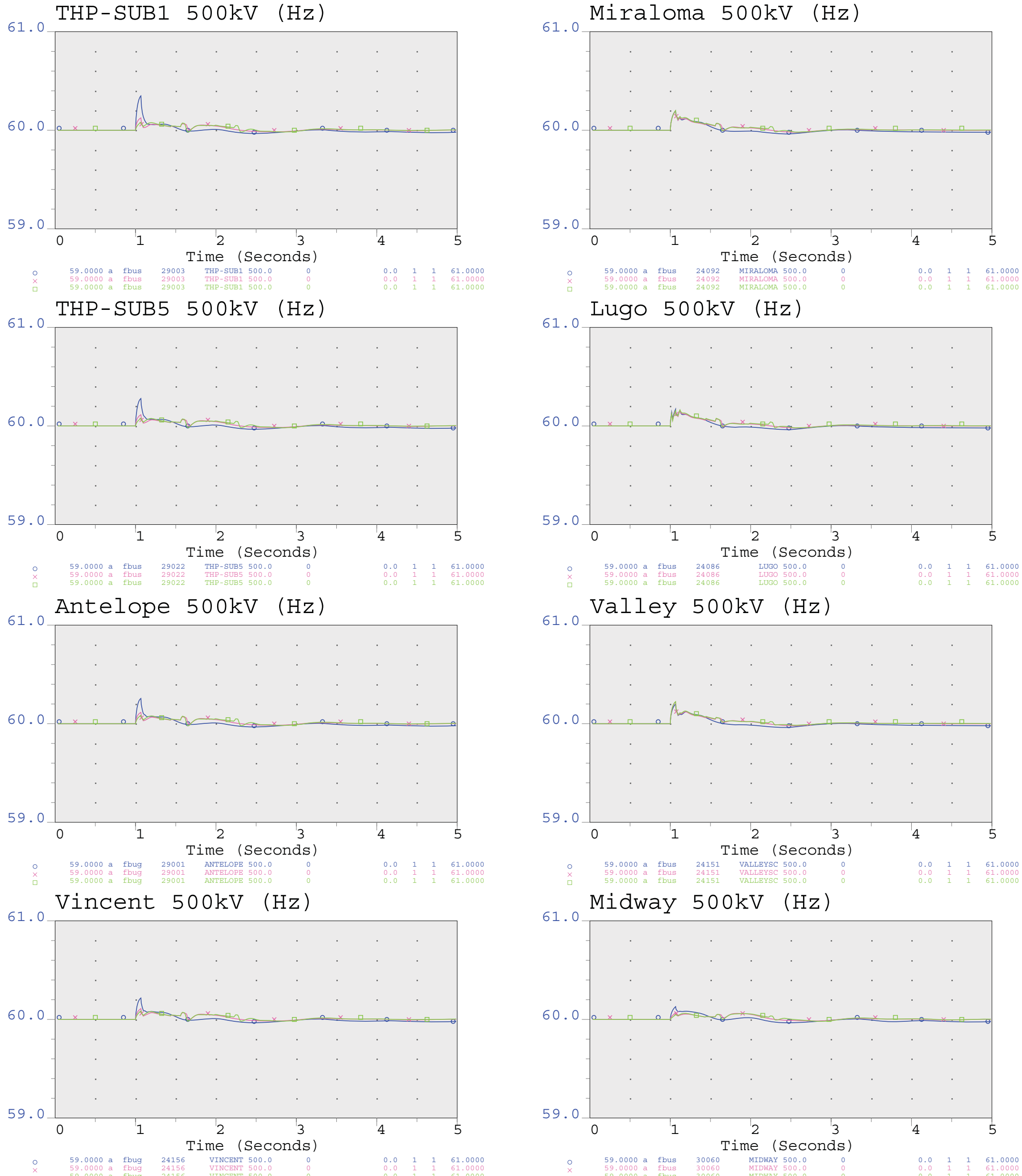
500kV Frequencies
Full Wind, Lo Wind, No Wind for Fault: 2012lspr-Lugo-Vincent-dlo



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Page 2

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230kV Voltages

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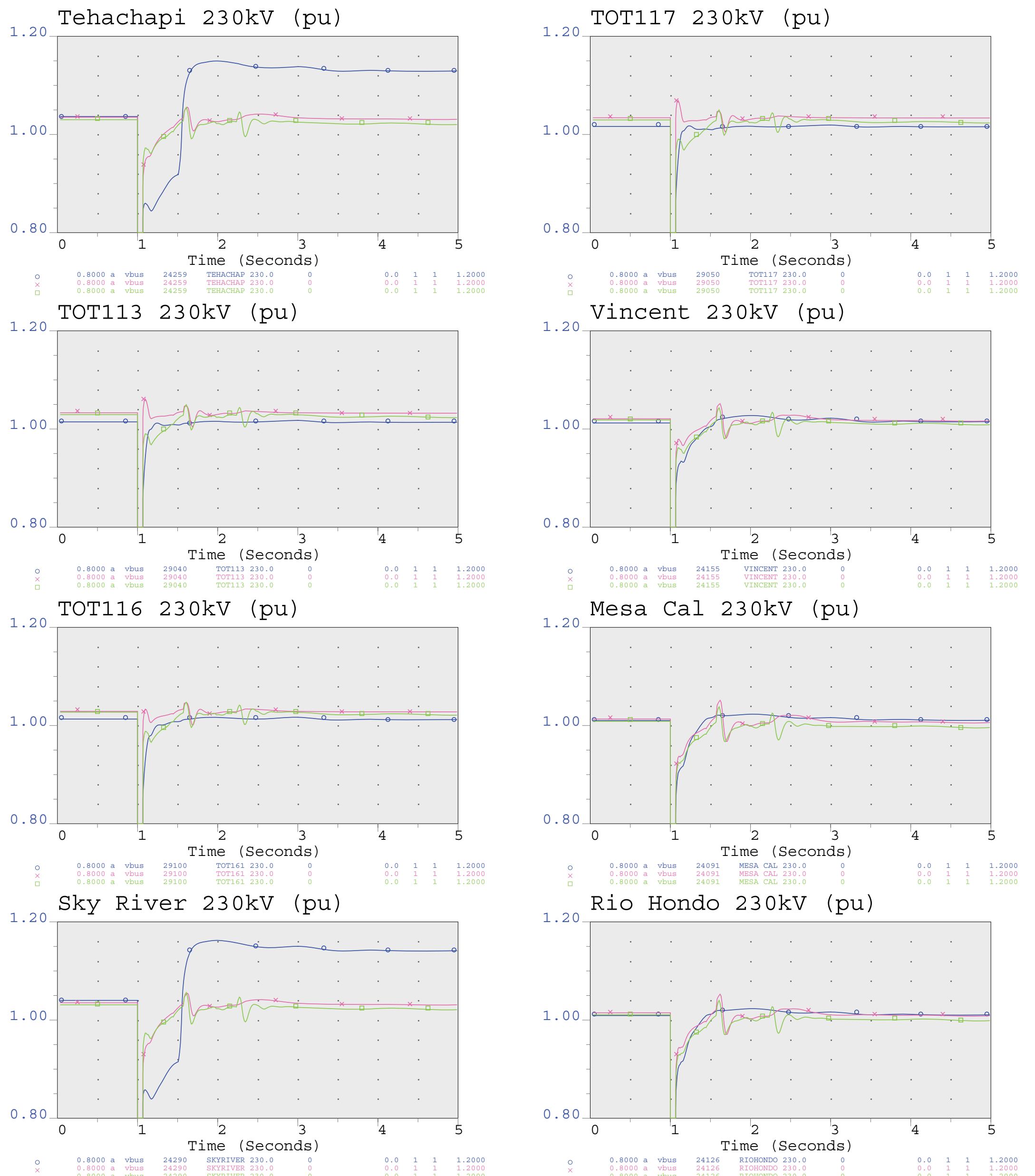

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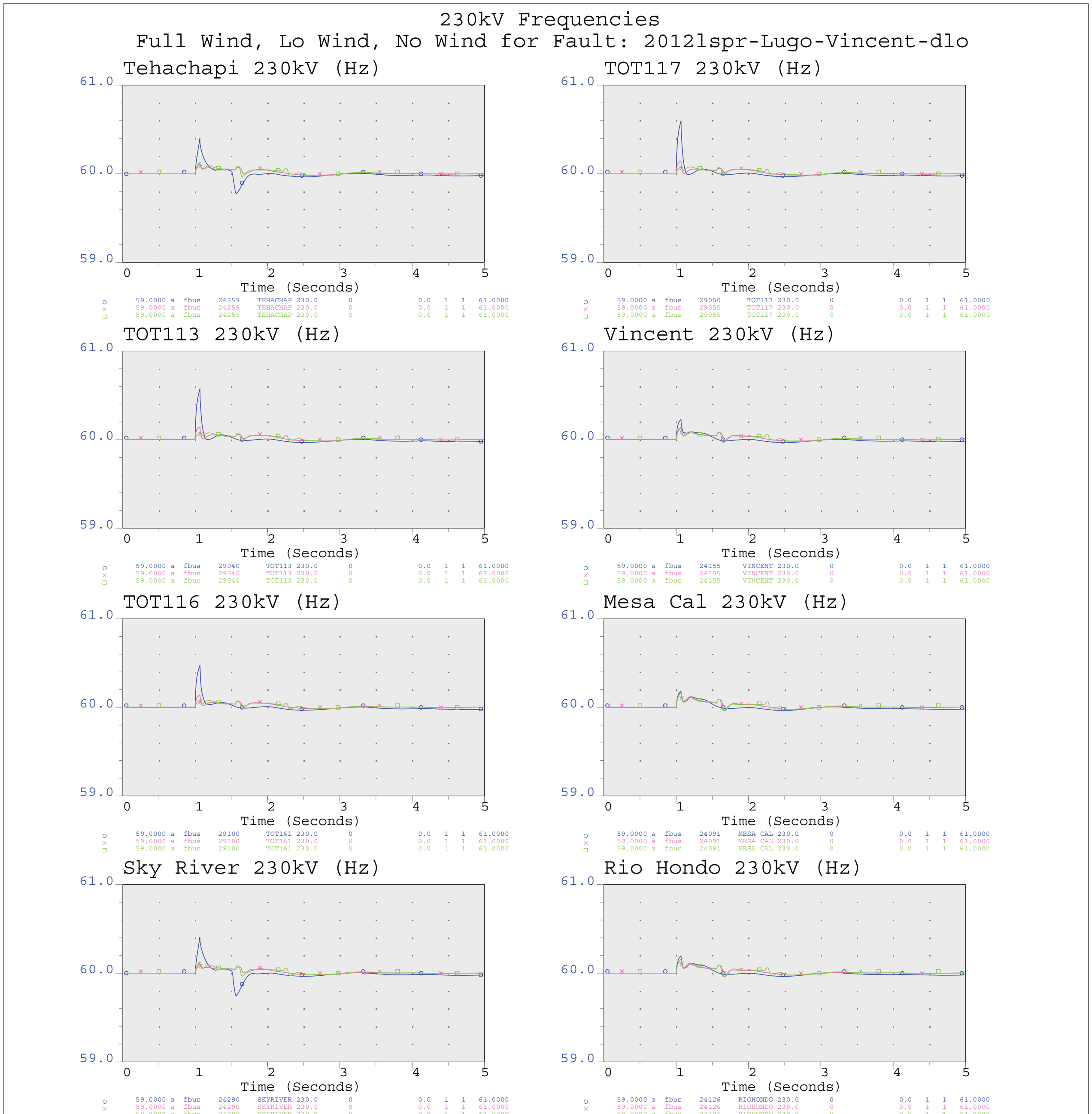

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500kV Real Power Flows
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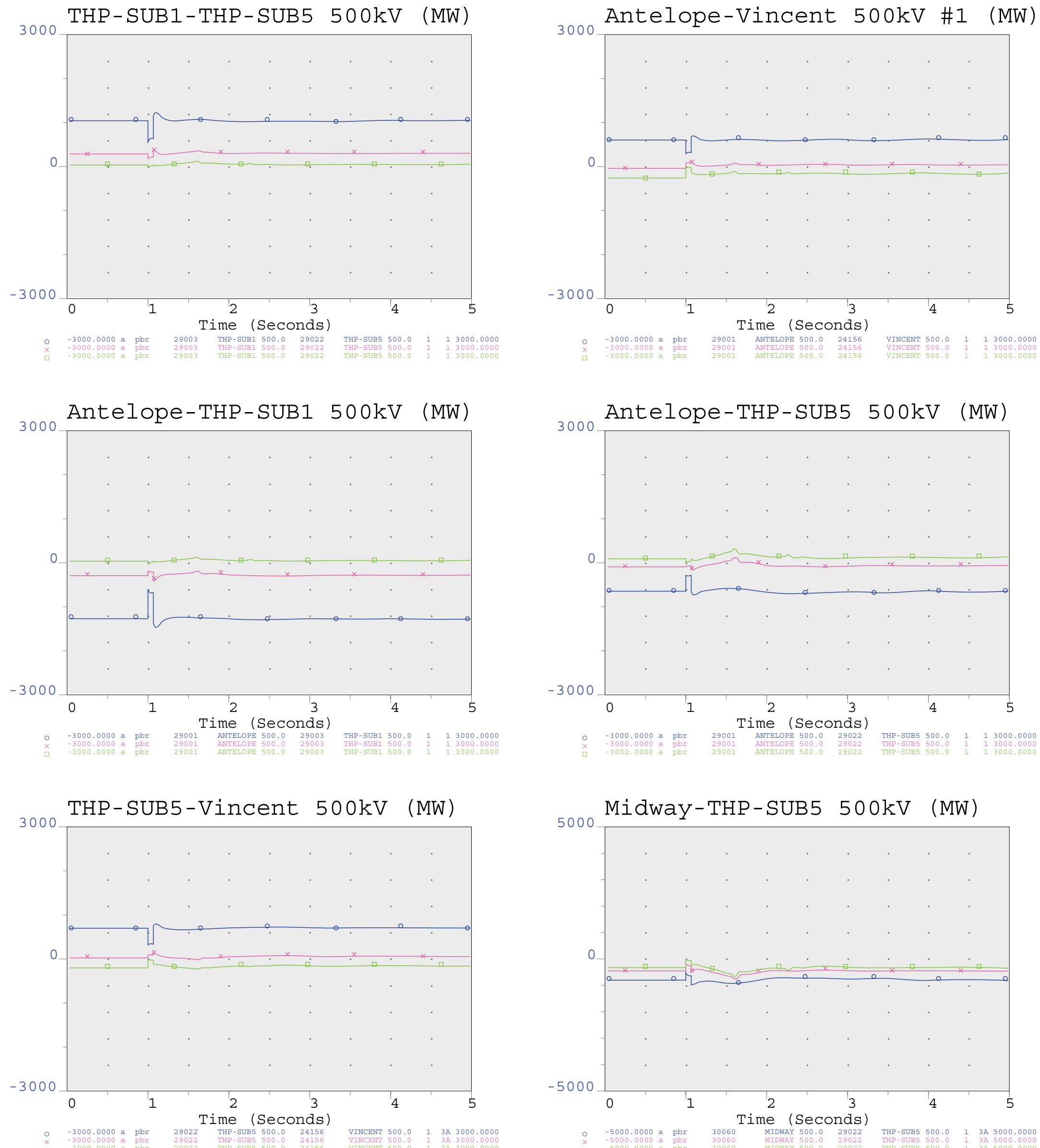

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Page 5

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500kV Reactive Power Flows
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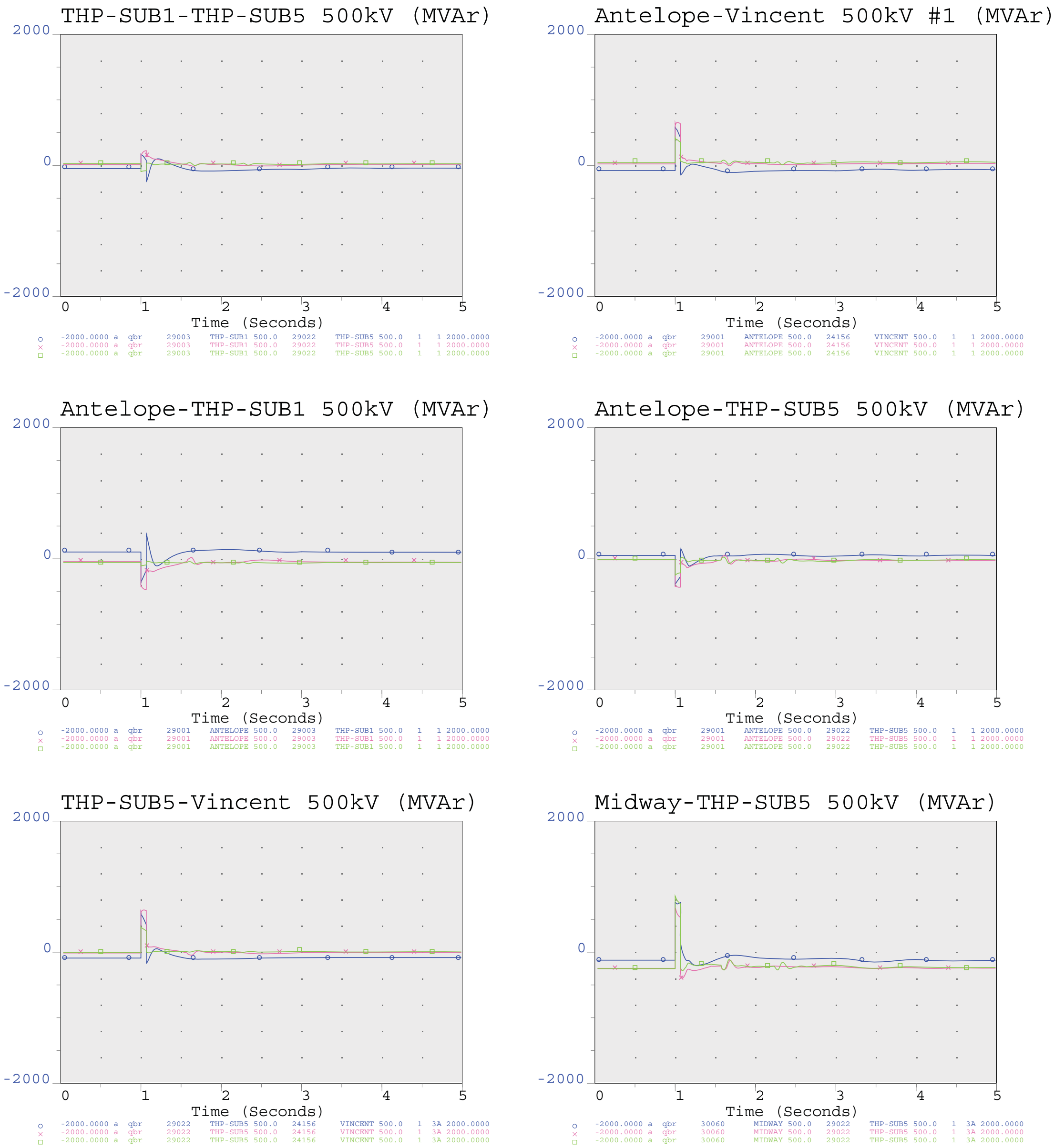

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Page 6

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Interface Power Flows
Full Wind, Lo Wind, No Wind for Fault: 2012lspr-Lugo-Vincent-dlo

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Page 7

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SVC Variables
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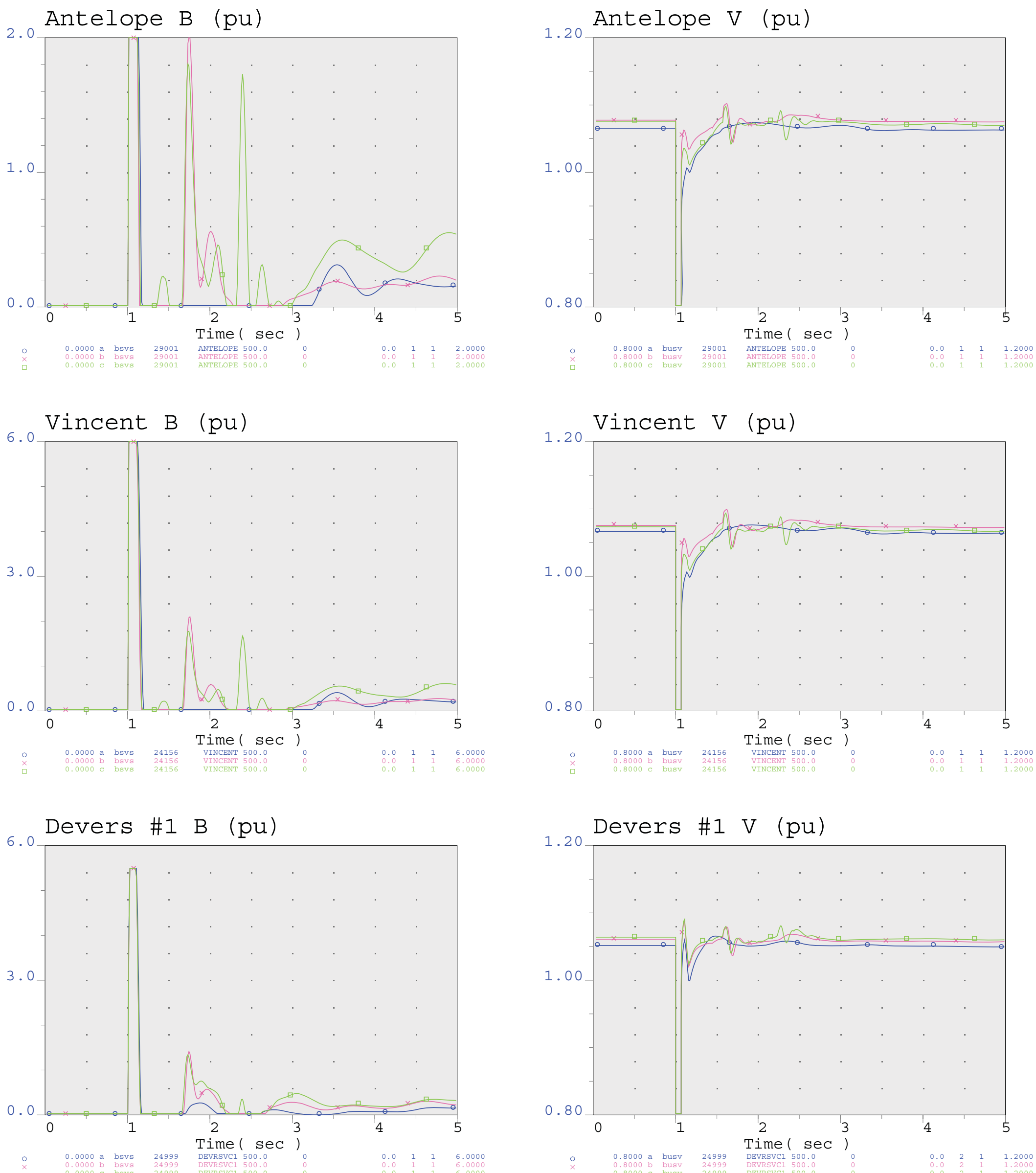

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Page 8

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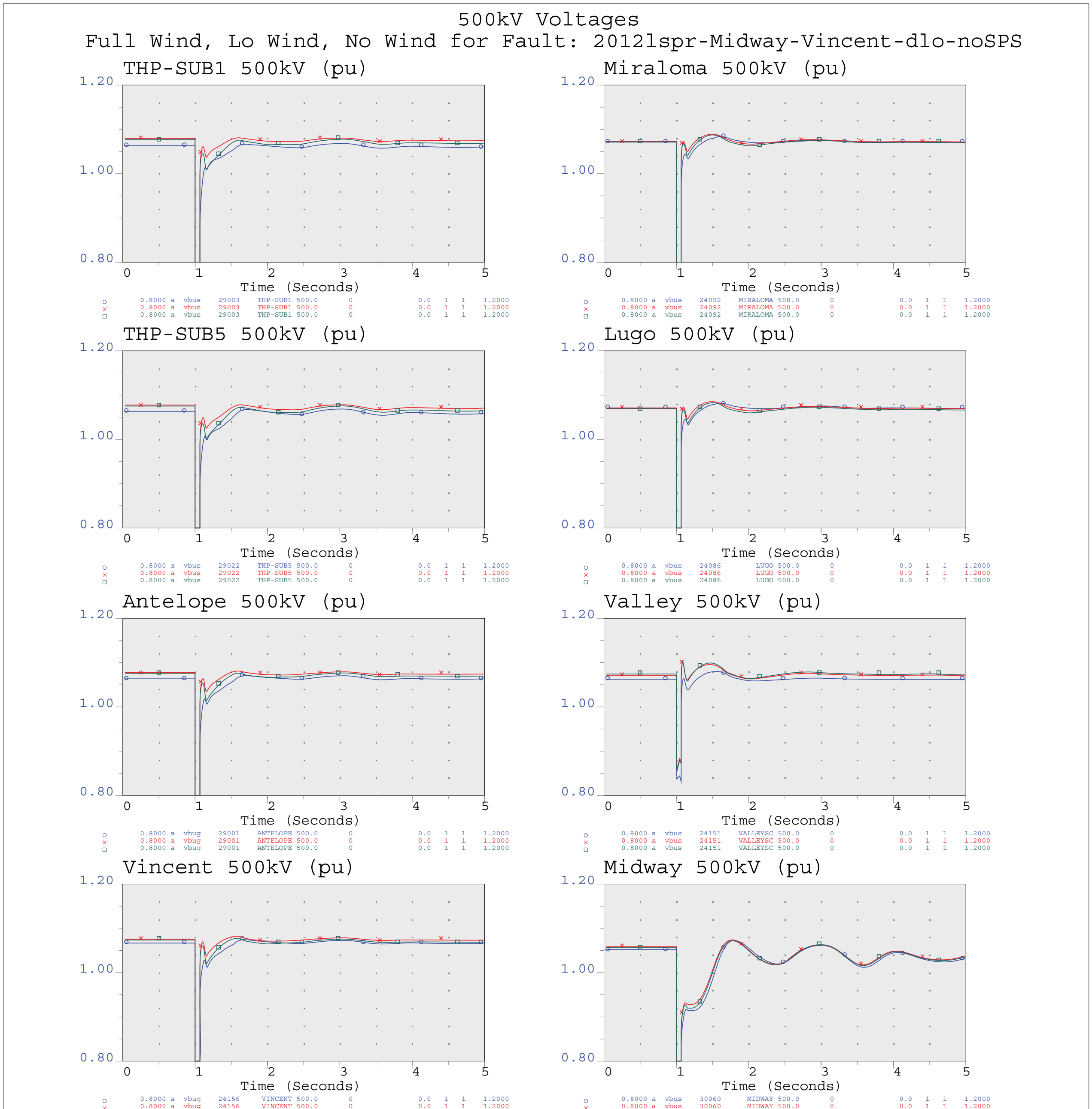

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SPS

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500kV Frequencies
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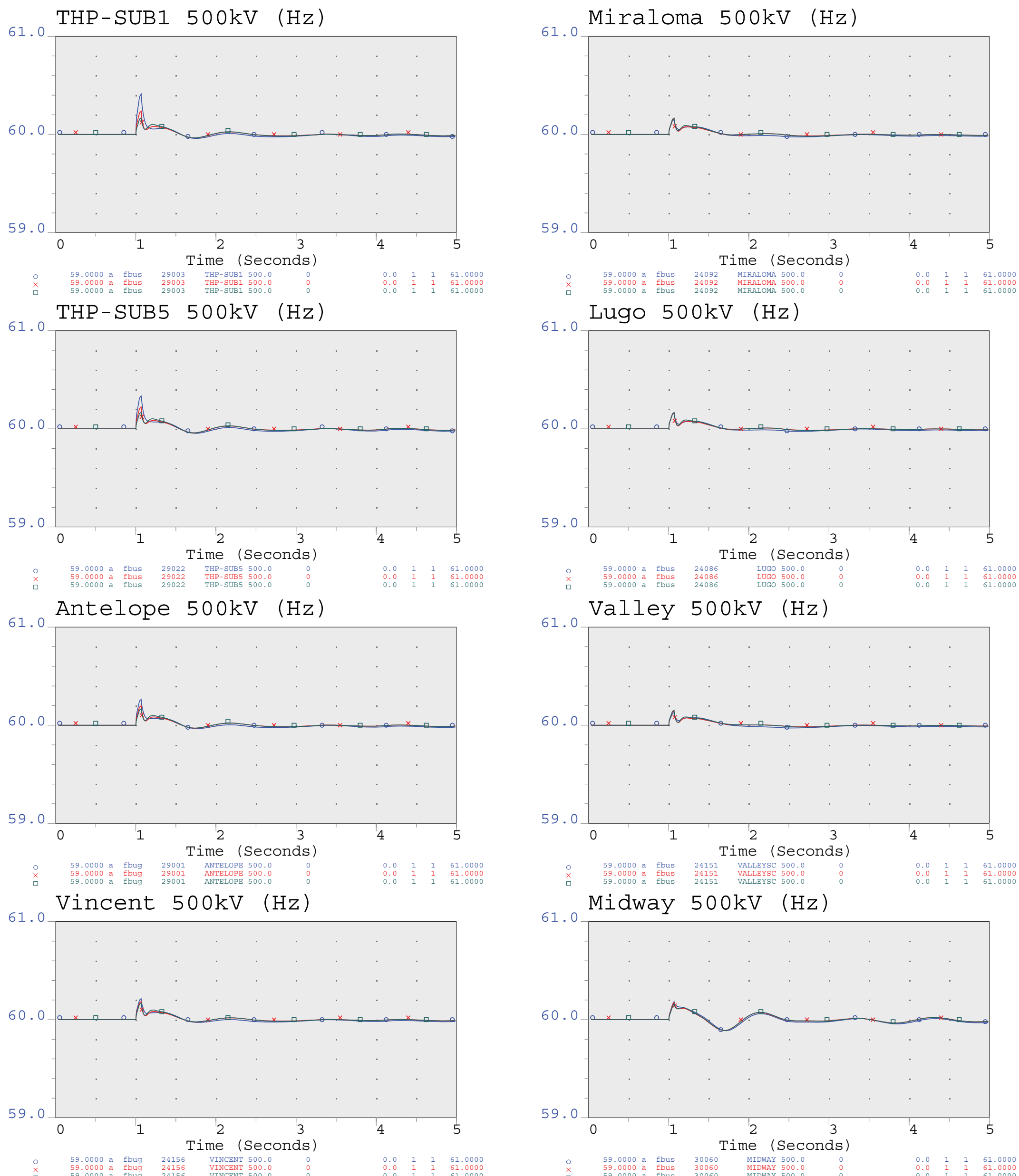

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230kV Voltages
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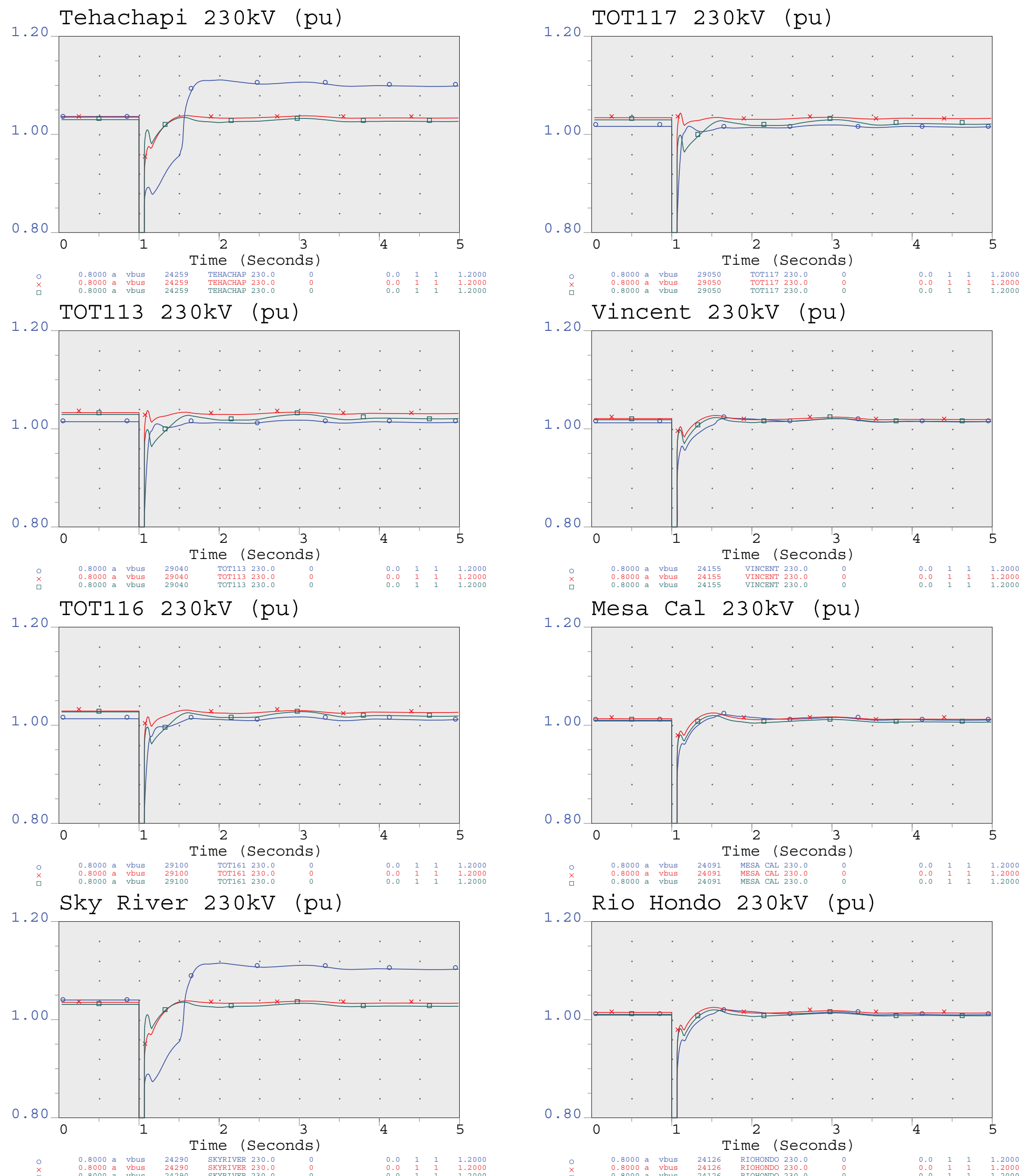

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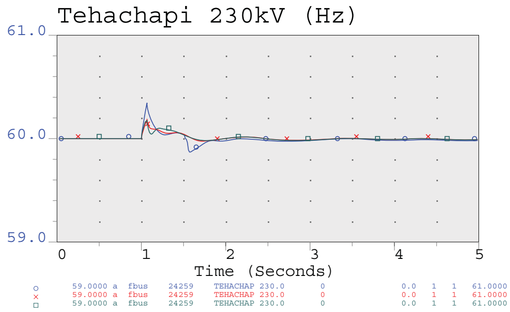

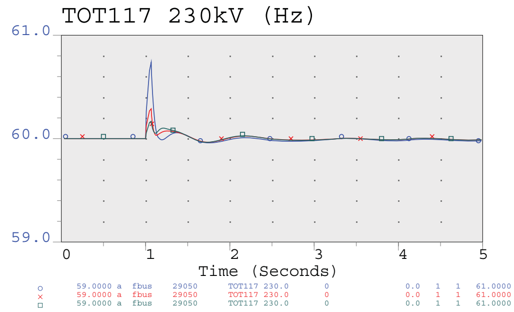

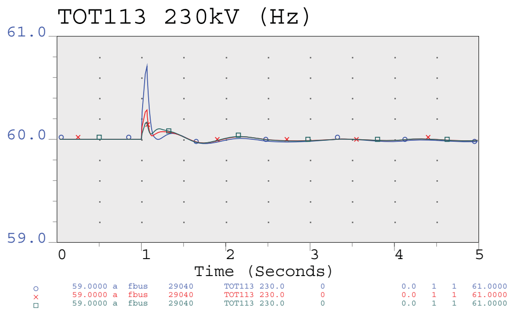

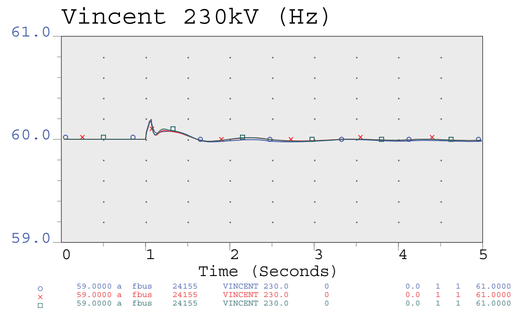

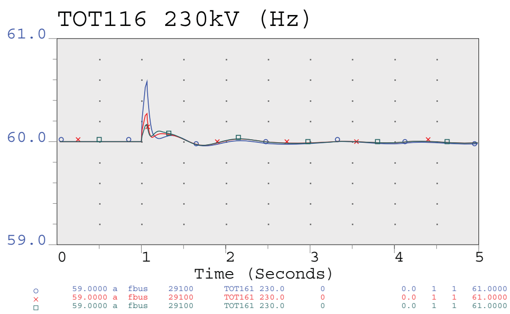

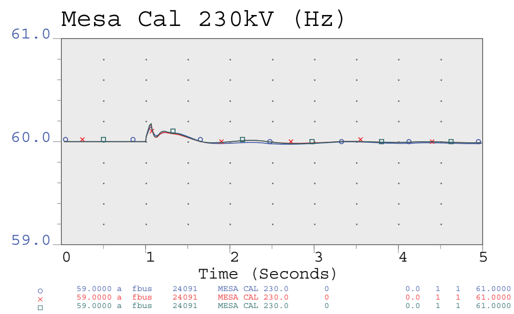

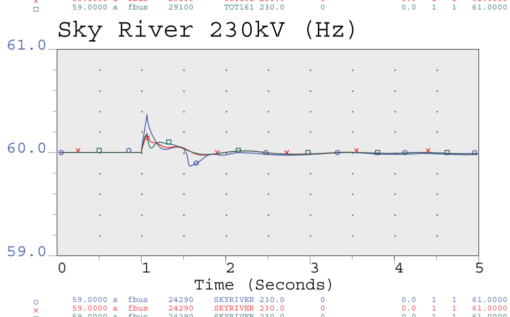

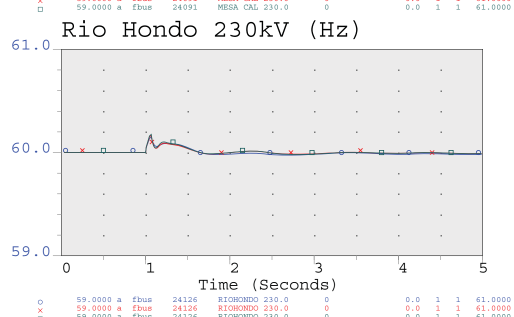

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500kV Real Power Flows
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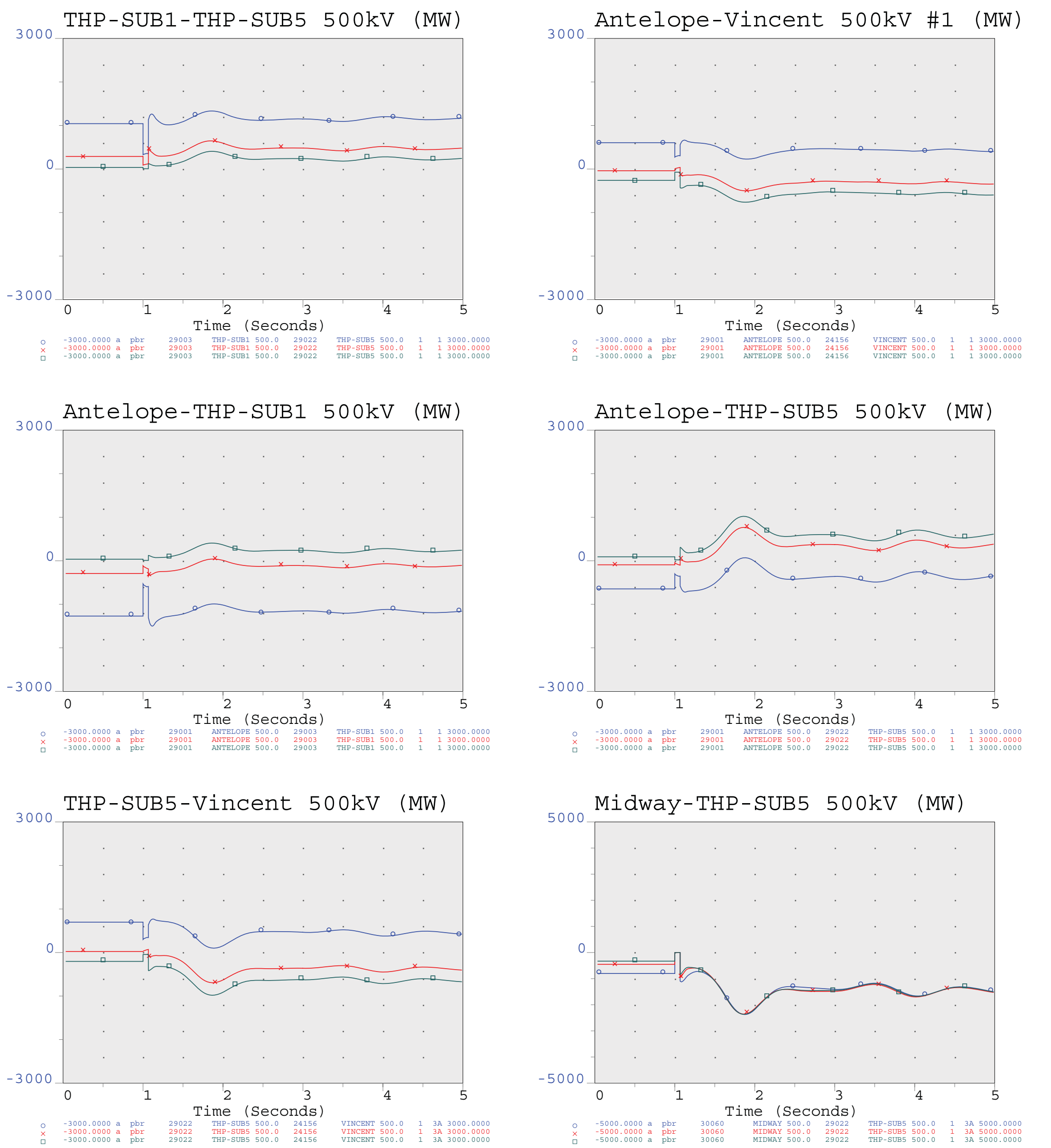

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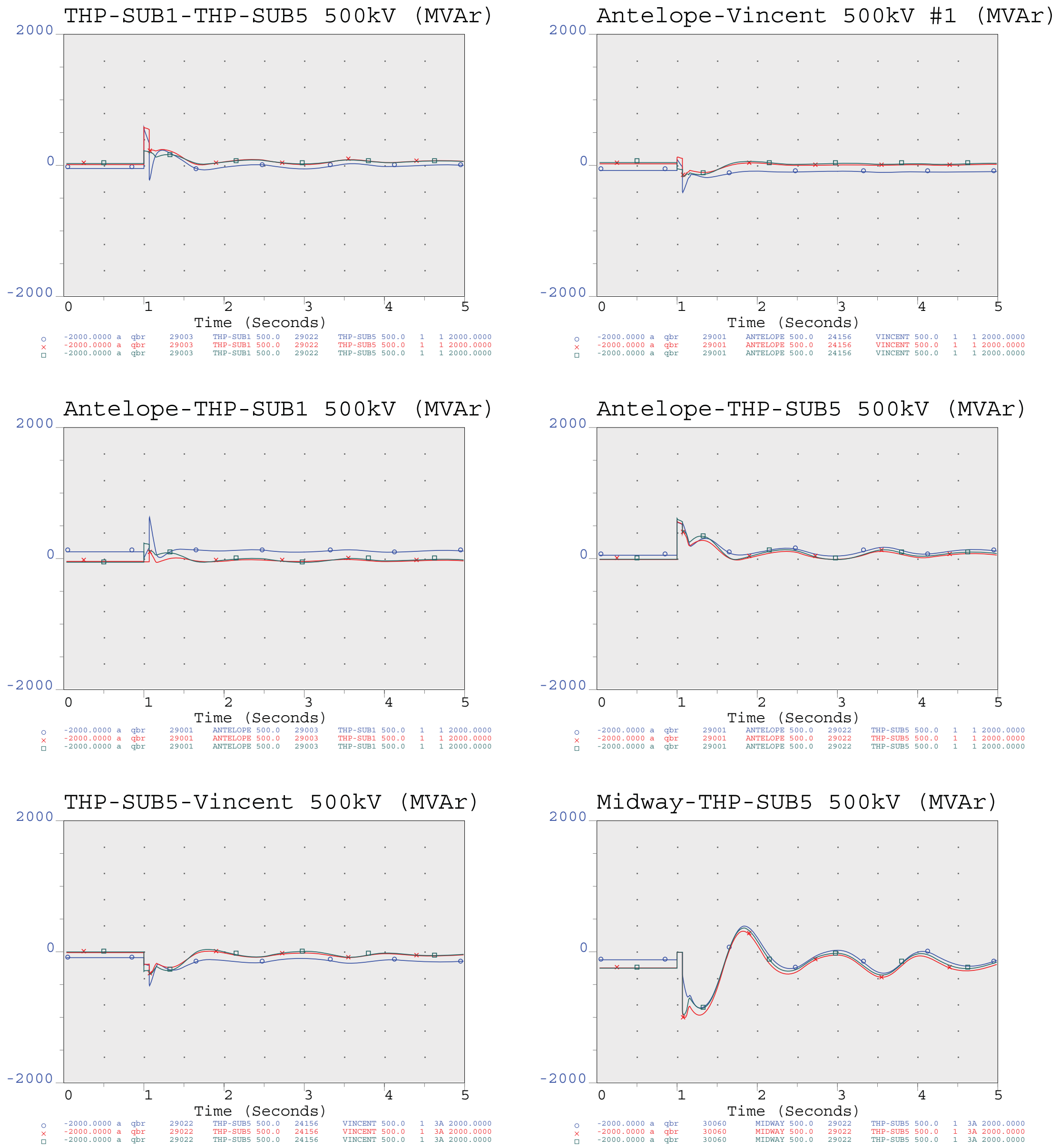

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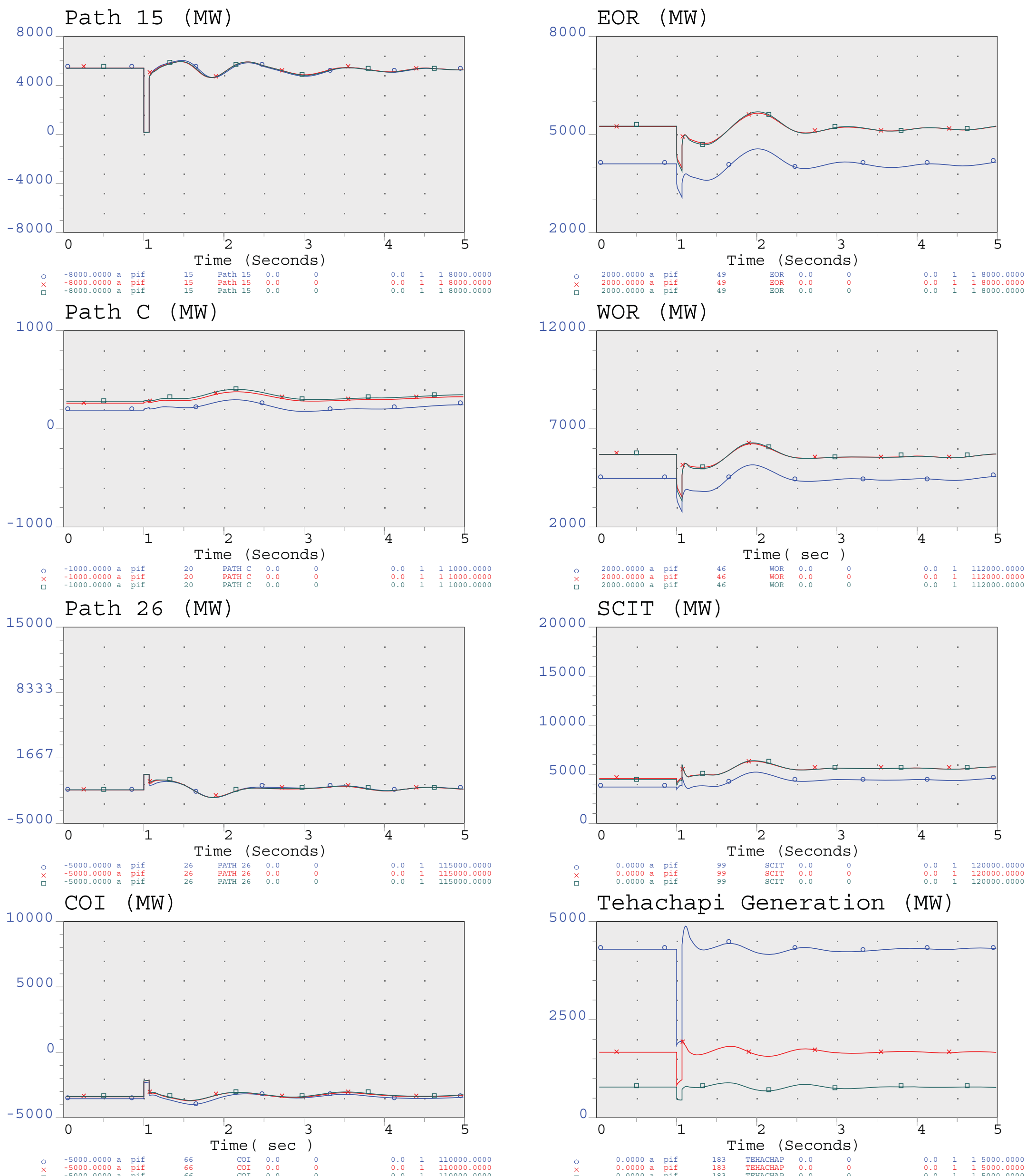

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Page 7

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SVC Variables
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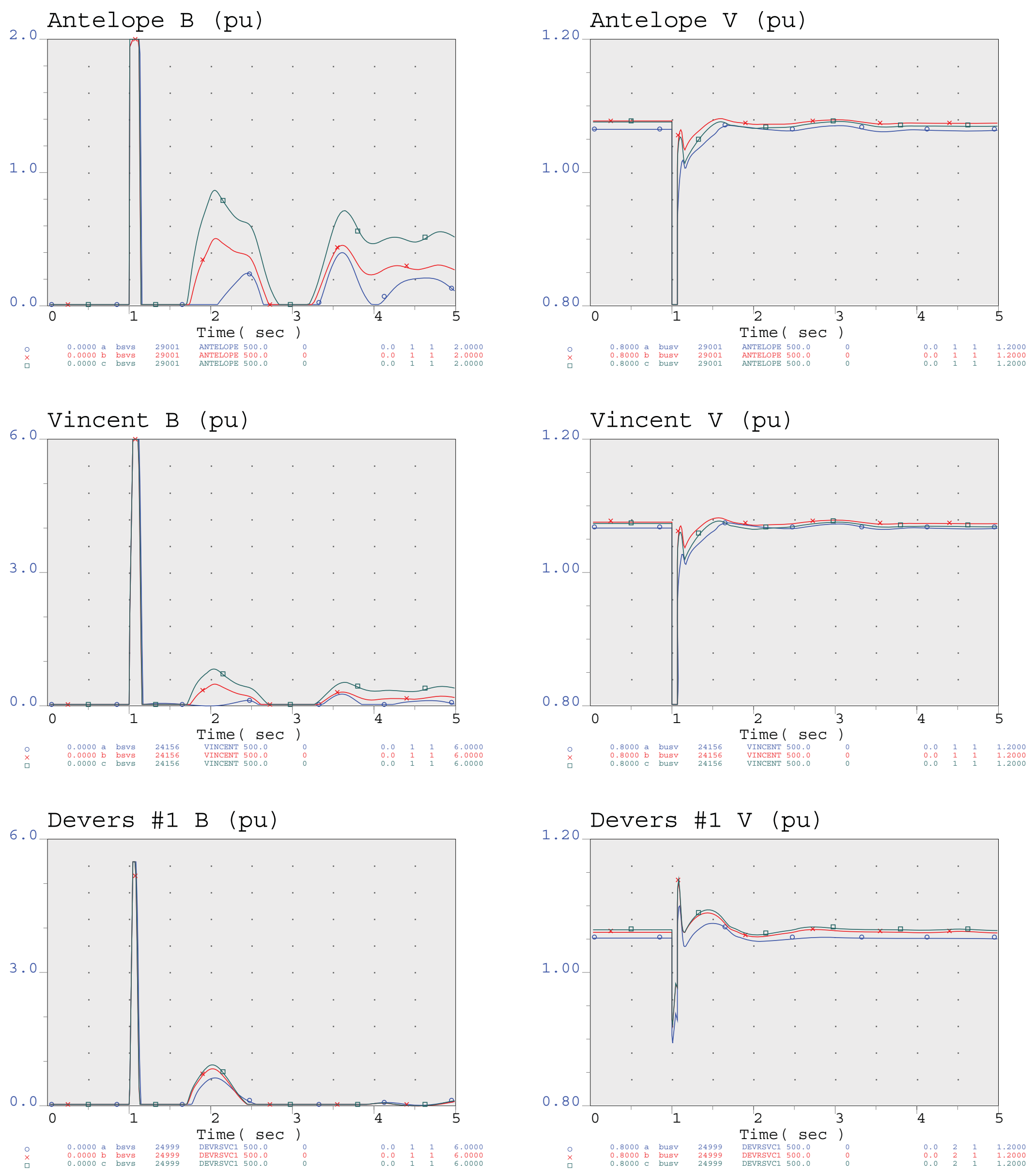

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Page 8

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ATTACHMENT D

Privileged treatment requested under
18 CFR § 388.112
(see Privileged Volume No. I for contents)

ATTACHMENT E

PIRP CALL COMMENT 3/20/09

VIASYN: Matthew Zito

There was quite a bit of concern from call participants that having to report outages "even as small as 1 MW" would be too time consuming and difficult. As a scheduling coordinator, VIASYN enters these outages into SLIC more or less daily and hourly if needed and it is neither difficult nor time consuming. As long as the wind (or solar) facility has a system that alerts them when a turbine (or panel) is malfunctioning and they know how much energy they are capable of generating, then it is simple to keep their availability updated in SLIC

ATTACHMENT F

Privileged treatment requested under
18 CFR § 388.112
(see Privileged Volume No. I for contents)

ATTACHMENT G

Table 1

A.14.2.4 Data Collecting Device Backup Power

Many sites provide the primary power for the meteorological stations and DPGs by either back feeding from the transmission line or directly from the wind turbine feeders. Each meteorological station and DPG must have a backup power source that is independent of the primary power source for the station (e.g., station power, battery or solar panel). The backup power source must provide power until primary power is restored. The same backup source can be used for both meteorological stations.

Measurement	Units	Accuracy
Wind Speed	Meters/Second (m/s)	+/-1 m/s
Wind Direction	Degrees from True North	+/- 5 degrees
Ambient Air Temperature	Degrees Centigrade (°C)	+/-1 degree C
Barometric Pressure	HectoPascals (HPa)	+/-60 Pa
Aggregate Resource Generation	Megawatts (MW)	+/-2%[5]

A.14.2.5 Training of Neural Network

Production and meteorological data will be collected for a minimum of sixty (60) days before the EIR can be certified as a PIR. This data must be collected in advance in order to train the forecast models (e.g., artificial neural networks) responsible for producing the power production (MW) forecast for each site.

A.14.2.6 Maintenance & Calibration

Meteorological equipment should be tested and, if appropriate, calibrated: (1) in accordance with the manufacturer's recommendations; (2) when there are indications that the data are inaccurate; or (3) when maintenance has been performed that may have interrupted or otherwise adversely impacted the accuracy of the data.

A.14.3 Solar Generator Forecasting and Communication Equipment Requirements

[5] See, Monitoring and Communication Requirements for Generating Units Providing Only Energy and Supplemental Energy, Section 2.5.