Q. Further to the response to PUB-NP-22, provide any information Newfoundland Power has as to other approaches that have been taken by utilities in other jurisdictions to minimize the impact on customers of rotating power interruptions.

A. Newfoundland Power is examining practices in other North American jurisdictions relating to rotating power outages in response to generation supply shortfalls. This forms part of Newfoundland Power's preparation to participate in the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System*.

To date, Newfoundland Power has assembled some information related to the practice and/or regulatory requirements in other jurisdictions with associated generation supply shortfalls, including rotating power outages. These jurisdictions currently include Alberta, California, Ontario and Texas.

This publically available information is provided in Attachments A though D to this response as follows:

Attachment A: Alberta
Attachment B: California
Attachment C: Ontario
Attachment D: Texas

Alberta

aeso
ALBERTA
ELECTRIC
SYSTEM
OPERATOR

AESO Report on the Load Shed Event of July 9, 2012

Table of Contents

Executive Summary

On July 9, 2012, Alberta experienced a supply shortfall event and was in a state of Energy Emergency Alert from 1:35 p.m. to 6:48 p.m. (the Event). High temperatures throughout the day drove Alberta's demand for electricity to an all-time summer high of 9,885 megawatts (MW) during the hour between 1:00 p.m. and 2:00 p.m., breaking the previous summer record of 9,552 MW set on July 18, 2011. The Alberta Electric System Operator (AESO) had forecast that a new record for summer peak demand would occur during the day and that supply would be sufficient to meet demand.

However, the Alberta Interconnected Electric System (AIES) experienced a lack of supply on July 9, 2012, due to a number of factors:

- One major coal generating unit was offline for scheduled maintenance, reducing supply by 362 MW
- Three major coal generating units and seven gas generating units experienced forced outages after generating unit trips, further reducing supply by approximately 1,469 MW
- Import available transfer capability was constrained by a number of factors, including lack of offers for the AESO's Load Shed Service for imports and lightning risk in the intertie corridor
- Wind power output was low, with an average capacity factor for the day of four per cent

This combination of high demand and unforeseen lack of generation capability created a need to reduce electricity consumption across the province. The AESO requested the Western Electricity Coordinating Council (WECC) Reliability Coordinator declare an Energy Emergency Alert 3 (EEA 3) and issued directives to shed 201 MW of electricity demand (also referred to as load) across the province at 2:10 p.m. The 201 MW represented approximately two per cent of AIES demand at the time, leaving 98 per cent of load across the province unaffected by the Event. The Event was the first time in six years that the AESO had issued directives to shed load in the AIES. Load shed directives remained in place until 5:14 p.m. At that time, those generating units impacted by forced outages returned to service and a decrease in load alleviated the supply shortfall condition. During the Event, the AESO issued a public appeal for Albertans to voluntarily reduce their power usage until such time that adequate supply could be restored to the AIES.

As per the requirements of Alberta Reliability Standards, the AESO conducted a detailed review of the Event and identified the sequence of events that led up to the load shed directive, together with the root causes of these events, and determined which corrective actions would be effective in alleviating power system reliability concerns. The AESO identified two factors that led to generating unit outages:

- The first was that some generating units were tripped off by temperature sensors and switches that had not been maintained or set properly, and high ambient temperature caused some sensors to be activated. The AESO will be requesting that generating unit facility owners review their maintenance practices, procedures and quality control programs with respect to these sensors.
- The second was that some generating units experienced derates to their available capability due to the high ambient temperature. The AESO plans to work with generating facility owners to ensure that this phenomenon is understood and considered in the AESO's load forecasts and market operations.

The Market Surveillance Administrator (MSA) investigated these outages and determined that no anticompetitive conduct took place. In addition to the MSA's findings, the AESO has not identified any instances of non-compliance with ISO Rules or standards by generating unit facility owners during the Event.

The AESO also reviewed the actions of the AESO system controller during the Event and found that overall, the system controller managed the Event in accordance with ISO Rules, Alberta Reliability Standards, and Operating Policies and Procedures (OPPs). Other than missing a minor inconsequential step in OPP 802; all ISO rules, Alberta Reliability Standards and Operating Policies and Procedures were met. The MSA extended forbearance on this one non-compliance incident. The system controller took appropriate action in maintaining the reliability and safety of the AIES, given the Event. In reviewing the AESO's supply shortfall procedures, the AESO has determined that a more comprehensive review of the supply shortfall steps and their effectiveness in managing supply shortfall events is needed, potentially leading to changes to supply shortfall rules and procedures. This review will take place in 2013.

The Supply Adequacy report shows the likelihood of a supply shortfall event for the current day and the next six days. The AESO has conducted a thorough analysis on the Supply Adequacy report as well as other AESO reports and forecasts that relate to supply shortfall events, including the load forecast and the wind power forecast. The Supply Adequacy report did not reveal any indication of an upcoming supply shortfall in the days leading to the Event. However, this attests to the sudden nature of the event as 1,469 MW of generation tripped within a short period of time. Overall, the analysis confirmed that these reports functioned as intended and that the Event was not caused by any inaccuracies in these reports or forecasts; however, the AESO will conduct a review of the short-term adequacy metrics in 2013 to determine whether any improvements can be made.

The AESO has reviewed its communication policies and practices applied during the Event. Communication to industry participants and the public was delayed due to technical issues with communication technologies and problems encountered with the AESO's internal processes. The Event was also unique in that the AIES went into EEA3 less than five minutes after system conditions met those described by an EEA2. This extremely tight timeframe contributed to challenges in communication. The AESO has revised staff responsibilities, resolved communication technology issues with its service providers, and implemented changes in department processes to ensure all staff are familiar with and have access to emergency procedures. Further, changes in the AESO's internal process have also been implemented to update industry contact lists and to test communications technologies on a monthly basis to ensure prompt communication to industry participants and the public. The AESO plans to hold a meeting with industry communicators to review roles, responsibilities and potential improvements with respect to emergency communications in 2013.

The central finding of all the analysis conducted is that the Event was a low-probability event caused by the coincidence of many small factors which are difficult to predict rather than by any one significant factor. The analysis shows that overall, the Event was managed adequately and system reliability was maintained. The AESO has made a number of recommendations and initiated a number of actions in the interests of continuous improvement that will enable the AESO to continue to operate the AIES in a safe, reliable, and efficient manner.

Introduction

On July 9, 2012, a hot summer day with record high electricity demand (also referred to as load), six generating plants went offline within three hours, causing a loss of electricity supply to the system and causing the Alberta Electric System Operator (AESO) to issue a directive to shed load (the Event). Events like this are rare, as the last time the AESO issued a directive to shed load was July 24, 2006. Overall, this supply shortfall event was handled in an effective manner, and established protocols were followed.

The Market Surveillance Administrator (MSA) monitors Alberta's electricity market for fairness and balance in the public interest. After the event of July 9, 2012, the MSA issued a notice[1] which provides background on the causes of the Event.

The AESO continuously seeks ways to better meet its mandate to provide for the safe, reliable and efficient operation of the Alberta Interconnected Electric System (AIES). The supply shortfall event of July 9 created an opportunity to test the AESO's processes and procedures for managing the AIES. The AESO has conducted an internal review of all processes and procedures that came into effect during the Event. This report summarizes the AESO's findings and the recommendations made based on the internal review.

Stock photograph.

1 *http://albertamsa.ca/uploads/pdf/Archive/2012/Notice%20July%209%20121102.pdf*

Background

The Independent System Operator (ISO), operating as the Alberta Electric System Operator (AESO) is an Alberta corporation established under the authority of the *Electric Utilities Act* and has a statutory obligation to provide for the safe, reliable and efficient operation of the AIES. The AESO employs a team of system controllers who monitor the AIES 24 hours per day, seven days per week. The AESO works with transmission facility owners (TFOs), distribution facility owners (DFOs), and generating unit facility owners (GFOs) to supply power to all Albertans. In times of supply shortfall, emergency plans are in place to maintain reliability of the entire system, including shedding load as a last resort. Shedding load refers to the temporary interruption of electricity supply to customers.

The AESO operates the AIES such that it is always prepared for the next likely future event that could disrupt the system, referred to as a contingency. To allow the AESO to prepare for the next possible contingency and operate the wholesale electricity market and the AIES in a safe, reliable manner, the Province of Alberta has set out a legislative and regulatory framework, including the *Electric Utilities Act* and the *Transmission Regulation*. The *Electric Utilities Act* imposes legal obligations on market participants, including distribution, transmission and generating facility owners. TFOs and DFOs are legally obligated to maintain their facilities in a manner that is consistent with the safe, reliable and efficient operation of the AIES. They are also obligated to assist the AESO in carrying out its duties, responsibilities and functions. This includes establishing procedures and systems for shedding load in emergencies.

The *Transmission Regulation* imposes further legal obligations on GFOs. GFOs are required to comply with both ISO Rules regarding outages and with directives the AESO issues for emergency procedures.

The AESO uses authoritative documents, consisting of ISO Rules, Operating Policies and Procedures (OPPs), Alberta Reliability Standards and the ISO Tariff as the basis to define the rights and obligations of the AESO and electricity market participants. Authoritative documents are developed with the input and support of market participants through the AESO's stakeholder consultation process, and are then filed with the Alberta Utilities Commission for confirmation. Compliance with the obligations set out in authoritative documents is mandatory for both market participants and the AESO.

ALBERTA WHOLESALE ELECTRICITY MARKET

The AESO operates the wholesale electricity market, enabling the sale and purchase of power in Alberta.

During normal system operation, generators of electricity offer their power into the market at their chosen price up to a ceiling of $999.99 per megawatt hour (MWh) on a day-ahead basis. These offers are sorted from the lowest to highest price for each hour of every day into a list called a *merit order*. The AESO's system controllers use the merit order to balance electricity supply and demand in real time, dispatching the lowest-priced supply offers and moving up to the highest until all electricity required is supplied. The electricity price is reflective of the highest priced supply dispatched to meet the total demand. The hourly average of these prices is called the pool price.

Alberta's electricity prices fluctuate due to the fundamentals of supply and demand. During normal system conditions, the pool price ranges from the price floor of $0/MWh to the offer cap of $999.99/MWh. During instances of supply surplus and low to moderate demand, prices are low, while times of supply scarcity and high demand drive prices higher.

In the event of a supply shortfall as occurred on July 9, when the system controller issues a directive to shed load, the pool price is administratively set at $1,000/MWh (as described in Section 201.6 of the ISO Rules *Pricing*). This action serves as an additional indicator to market participants of the supply shortfall status.

Alberta has two interties, one with British Columbia (B.C. intertie) and one with Saskatchewan (Saskatchewan intertie). For each intertie, the AESO sets a specified available transfer capability (ATC), the amount of energy that can be transferred into and out of the province via that intertie. The ATC on either intertie will vary depending on studied system conditions. The actual amount of energy that is imported or exported is determined by market conditions and may be less than the ATC.

SUPPLY SHORTFALL

On the afternoon of July 9, 2012, the AIES experienced a period of supply shortfall. A supply shortfall occurs when there is insufficient electricity generation available in the wholesale market to meet the total Alberta demand for electricity. The total installed capacity for electricity generation in Alberta is sufficient to meet demand in most conditions, but a supply shortfall can be triggered when a large volume of electricity supply becomes unexpectedly unavailable due to technical problems, transmission issues or when demand from Alberta electricity consumers is higher than anticipated.

When a supply shortfall occurs, the AESO works with market participants to maintain the reliability of the AIES and to restore adequate electricity supply to meet consumer demand as soon as possible.

During a supply shortfall situation, the AESO follows a series of procedures currently found in Section 202.2 of the ISO Rules, *Short Term Adequacy and Supply Shortfall* [2] to balance supply and demand and preserve the reliability of the AIES. On July 9, 2012, the AESO was operating under former OPP 801 *Supply Shortfall*, which contained the same requirements as Section 202.2, and this report refers to the procedures and requirements as they appeared in OPP 801.

During supply shortfall conditions, the AESO curtails exports on the interties and can consider increasing power imported into Alberta by raising the import ATC and/or requesting emergency imports.

The AESO requests Energy Emergency Alerts (EEAs) from the Western Electricity Coordinating Council (WECC)[3] Reliability Coordinator in accordance with former OPP 802 *Energy Emergency Alerts and Firm Load Shed Directives*, which was replaced by Section 305.1 of the ISO Rules Energy and Emergency Alerts. Four levels of EEAs may be issued in an energy supply shortfall, summarized here as follows:

Energy Emergency Alert 1 (EEA1)

In this first alert state, all the energy available in the merit order is being utilized, but the operating reserve remains intact. The AESO maintains approximately 500 megawatts (MW) of contingency reserve (a type of operating reserve) at all times that serves as a safety net of extra dispatchable generation. To the extent it is available, energy continues to be imported through Alberta's interties to British Columbia and Saskatchewan, while energy exports to British Columbia and Saskatchewan are curtailed.

Energy Emergency Alert 2 (EEA2)

In this second alert state, contingency reserve, normally held as spare capacity, is used to meet electricity demand and service to consumers is not yet impacted. The AESO issues directives to providers of operating reserve to meet electricity demand. Emergency energy is requested of neighbouring jurisdictions through Alberta's interties. Depending on system conditions, a public communication may be issued to request customers to voluntarily reduce demand.

[2] *Section 202.2 came into effect on January 8, 2013.*

[3] *WECC: The Regional Entity responsible for coordinating and promoting Bulk Electric System Reliability in multiple western U.S. states and Alberta and British Columbia.*

Energy Emergency Alert 3 (EEA3)

In this third and highest alert state, the AESO issues a directive to DFOs to shed load on their systems. This means that DFOs activate plans to temporarily interrupt services to customers in order to reduce load so that the integrity of the AIES is not jeopardized and can continue to be operated reliably.

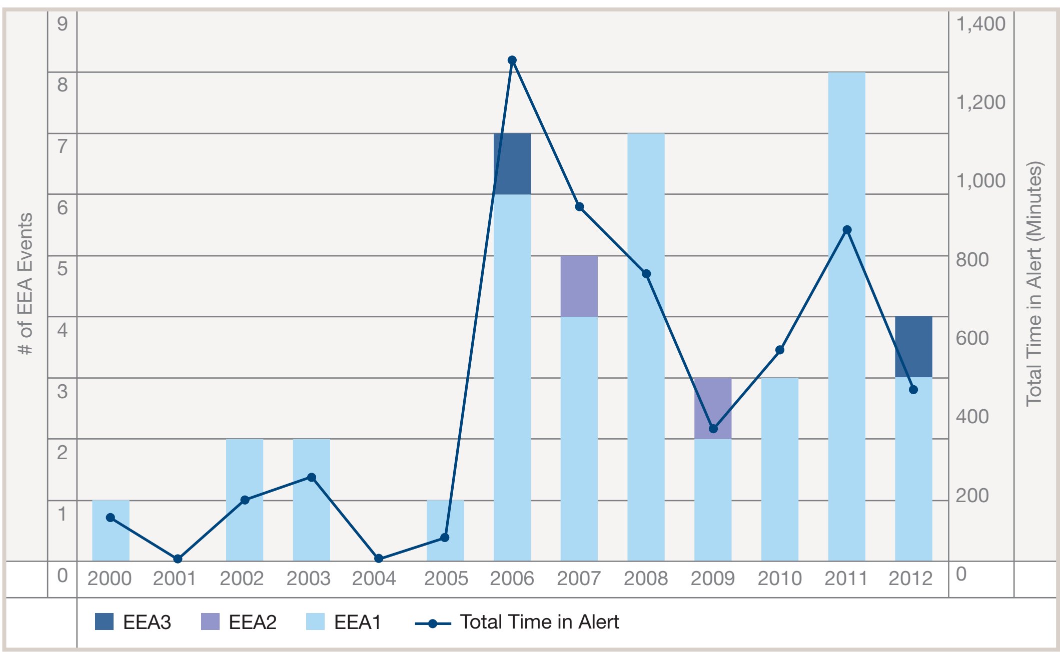
Energy Emergency Alert 0 (EEA0)

EEA0 is issued to terminate all previous energy emergency alerts when energy supply is restored, and is intended to indicate that there is no longer a supply shortfall.

Since 2000, when Alberta began tracking EEA metrics, Alberta has experienced a total of 42 EEA events with two of those events reaching EEA3 (i.e., shedding of electricity load). The first of these EEA3 events happened on July 24, 2006 and the second on July 9, 2012.

Figure 1 below depicts EEA events since 2000 including total time spent in EEA events.

FIGURE 1
Energy Emergency Alerts



Events of the Day

On July 9, 2012, Alberta experienced a supply shortfall event and was in a state of Energy Emergency Alert from 1:35 p.m. to 6:48 p.m. which required the shedding of load from 2:10 p.m. to 5:14 p.m. Record-high summer demand for electricity and reduced energy availability both played a significant role in the Event as outlined below.

Average temperature for the province was 24°C with a peak temperature for the day of 32°C. Historically, an increase of one degree Celsius (C) has been correlated with an approximate 50 MW increase in peak electricity demand during the summer months[4]. These high temperatures drove Alberta's demand for electricity to an all-time summer high of 9,885 megawatts (MW) between 1:00 p.m. and 2:00 p.m., breaking the previous summer record of 9,552 MW set on July 18, 2011. The AESO forecast this record high demand accurately through the day-ahead load forecast and predicted that supply would be sufficient to meet demand throughout the day. For more information on the AESO's forecasts and reports, see the Market Impacts section of this report.

The AIES experienced a lack of supply on July 9, 2012, due to a number of factors:

- The Sundance 3 generating unit was offline for scheduled maintenance, reducing supply by 362 MW.
- Three major coal generating units (Battle River 5, Keephills 1, and Genesee 2) and seven gas generating units (Balzac, Poplar Hill, Mahkeses, Joffre and Crossfield) experienced forced outages after generating unit trips, further reducing supply by approximately 1,469 MW. For more information on the role of generating unit outages in the Event, see the Power System Reliability section of this report.
- Imports were constrained by several factors discussed in more detail in the Power System Reliability section of this report.
- Wind power output was low, with an average capacity factor for the day of four per cent.

[4] *http://www.aeso.ca/downloads/AESO_2012_Market_Stats.pdf*

This combination of high demand and unforeseen lack of generation capability in the AIES created a need to balance electricity demand and production across the province by increasing generation through emergency measures or reducing demand. The AESO implemented procedures as prescribed in OPP 801 to increase generation and reduce demand, including (but not limited to) the following:

- The AESO increased generation through emergency measures such as:
  - Dispatching contingency reserve to provide energy;
  - Cancelling transmission maintenance; and
  - Requesting emergency energy from the Northwest Power Pool and Saskatchewan.
- The AESO reduced demand through:
  - Directing certain market participants who purchase electricity under Demand Opportunity Service (DOS) (interruptible load program) to curtail load;
  - Eliminating exports from Alberta; and
  - Issuing a public appeal to Albertans to conserve energy.

After performing the steps outlined above and other effective steps, the supply shortfall remained. The AESO requested the WECC Reliability Coordinator declare an EEA3 and issued directives to shed 201 MW of load across the province at 2:10 p.m. These 201 MW represented approximately two per cent of AIES demand at the time, leaving 98 per cent of load across the province unaffected by the Event. By 5:14 p.m., those generating units impacted by forced outages were returning to service, which coupled with a decrease in load alleviated the supply shortfall condition. This allowed all load to be restored. For more information on the load shed and the other steps used to balance supply and demand throughout the Event, see the System Controller Action section of this report.

As noted above, the AESO issued a public appeal for Albertans to voluntarily reduce their power usage during the Event until adequate supply was restored to the AIES. Further information regarding Communication during the Event is discussed in the Communication section of this report.

System Controller Action

As required by Section 202.2, the AESO must perform a short-term adequacy (STA) assessment for every hour of the current trading day and for every hour of the following six days. This automated adequacy assessment (calculations for the assessments are found in Information Document ID#2012-006(R) *Short Term Adequacy and Supply Shortfall*) allows the AESO's system controller to determine whether a supply shortfall is likely to occur over any of the hours for which the assessment is performed. If the assessment shows a supply shortfall is likely, then the system controller will take certain steps (contained in internal AESO operating procedures and outlined in ID#2012-006(R)) to mitigate and manage the potential supply shortfall event. Results of the adequacy assessment are updated every five minutes and posted to the AESO website.

On July 9, 2012, and in the days preceding, the STA assessment indicated sufficient supply to meet the load forecast for the day, even though the AESO's load forecast predicted record high levels of load. With the assessment showing there were no adequacy issues, the steps contained within ID#2012-006(R) were not initiated.

On July 9, 2012, there was no indication of a supply shortfall until 1:06 p.m., when a trip of the Keephills 1 generating unit decreased supply by approximately 393 MW. In response to this trip, the system controller immediately issued a directive for 200 MW of contingency reserve to meet the requirements of the Alberta Reliability Standards and balance the AIES. This directive remained in effect at the time the AESO entered EEA1 at 1:35 p.m.

By 1:07 p.m., the system controller had dispatched all assets in the AESO's merit order to maintain the balance between supply and demand leaving no supply cushion to meet increases in demand. At 1:07 p.m., an on-duty Real-time Manager and the AESO's Director of Grid and Market Operations were notified that the merit order had been fully dispatched.

In a supply shortfall event, the system controller is required to increase the import ATC and decrease the export ATC. On July 9, 2012, at the time of the Event, import ATC on the B.C. intertie was already maximized given AIES conditions and weather conditions. For more detail on import ATC during the supply shortfall event, see the Power System Reliability section of this report. Export ATC was already constrained to zero due to the high load levels in the Province, and this was confirmed by the system controller at 1:15 p.m.

At 1:21 p.m. the system controller directed a seven minute DOS customer to maintain their then-current consumption of 0 MW. There was no pre-approved one hour DOS or Standard DOS to curtail at the time of the Event.

In a supply shortfall event, the system controller is required to cancel planned transmission maintenance when doing so will remove generation constraints or will increase import ATC on the interties. At 1:15 p.m., the system controller cancelled a previously scheduled outage to the ENMAX 162.8 line, which was constraining generating units in the North Calgary area. ENMAX restored the line at 2:03 p.m., effectively removing the constraints and increasing generation from the constrained units by approximately 50 MW. At 2:04 p.m., the system controller requested BC Hydro restore their 2L113 line in order to increase import ATC on the Alberta-B.C. intertie. The line was returned to service at 3:48 p.m. and relieved the supply shortfall by approximately 70 MW. For more information on the cancellation of transmission maintenance on the intertie, see the Power System Reliability section of this report.

EEAs must be declared by the WECC Reliability Coordinator. When the AIES reached EEA1 conditions (meaning all energy in the merit order had been dispatched), the system controller requested the WECC Reliability Coordinator to declare an EEA1. The WECC Reliability Coordinator agreed to the request and declared an EEA1 at 1:35 p.m. The system controller notified required parties (as set out in OPP 802) of the EEA1 at 1:44 p.m. At 2:01 p.m., as required by OPP 801, the Director, Grid and Market Operations informed Corporate Communication of the operating situation. For more information on Corporate Communication actions regarding the Event, please see the Communication section of this report. By 2:02 p.m., all DFOs had been notified of the possibility of load shedding and were informed of their possible load shed level.

At 1:55 p.m., the system controller disabled WECC validation for e-tags and notified market participants that the AESO would accept mid-hour interchange transactions up to the posted import ATC limit. This permits intra-hour interchange transactions in order to maximize imports up to posted ATC outside of the normal market timing parameters during the Event.

At 1:57 p.m., the system controller requested the City of Red Deer to institute a three per cent distribution voltage reduction in accordance with OPP 801.

By 2:00 p.m., Alberta internal load had hit a new all-time summer peak load of 9,885 MW for the hour between 1:00 p.m. and 2:00 p.m.

At 2:06 p.m., system conditions had reached EEA2 levels. The system controller entered into the AIES Event Log that EEA2 had been declared, even though it had not yet been requested from WECC. Another sudden generating unit trip (of 400 MW from the Genesee 2 generating unit) at 2:07 p.m. and the resulting requirement to shed load to meet reliability criteria caused the system controller to request that WECC declare EEA3, skipping any official declaration of EEA2. At 2:10 p.m., the WECC Reliability Coordinator declared EEA3. Concurrent with the declaration of EEA3, the system controller directed the shedding of 201 MW of load, which was shared between wire owners on a pro-rata basis as required in ISO Rule 6.8 *Involuntary Load Curtailment*.

Between 2:10 p.m. and 2:15 p.m., the system controller issued load directives to the following market participants:

- At 2:10 p.m., AltaLink was directed to curtail 106 MW
- At 2:10 p.m., EPCOR was directed to curtail 36 MW
- At 2:10 p.m., ATCO was directed to curtail 18 MW
- At 2:11 p.m., ENMAX was directed to curtail 32 MW
- At 2:12 p.m., the City of Lethbridge was directed to curtail 4 MW
- At 2:13 p.m., the City of Red Deer was directed to curtail 4 MW
- At 2:15 p.m., Fort Nelson was directed to curtail 1 MW

At 2:09 p.m., the system controller requested emergency energy from Saskatchewan Power Corporation (SaskPower). SaskPower was able to provide 60 MW of emergency energy at 2:24 p.m., and at 3:00 p.m. was able to increase the emergency energy to 100 MW. This request remained in effect until 5:12 p.m.

At 2:15 p.m., the Mahkeses generating unit was forced out of service, reducing supply by approximately 71 MW.

At 2:16 p.m., Corporate Communication was advised that EEA3 had been declared and that 200 MW of load was to be curtailed.

At 2:18 p.m., due to the loss of generation from the Genesee 2 and Mahkeses facilities, the system controller made a request for energy from the Northwest Power Pool (NWPP) Reserve Sharing Group and received 50 MW of contingency reserve from NWPP. This request was terminated at 3:16 p.m., as NWPP reserves are only available for a one hour duration.

At 3:39 p.m., after Mahkeses came back online and Sundance 3 returned to service from scheduled maintenance, the system controller started issuing directives to return 100 MW of load to service:

- At 3:39 p.m., EPCOR was directed to restore 18 MW
- At 3:40 p.m., ATCO was directed to restore 9 MW
- At 3:40 p.m., ENMAX was directed to restore 16 MW
- At 3:41 p.m., the City of Lethbridge was directed to restore 2 MW
- At 3:41 p.m., the City of Red Deer was directed to restore 2 MW
- At 3:42 p.m., AltaLink was directed to restore 53 MW

At 3:52 p.m., the system controller made another request for 80 MW of reserve from the NWPP after the Joffre generating unit tripped offline, reducing supply by approximately 205 MW. This request was terminated at 4:14 p.m.

At 5:00 p.m., Joffre came back online and began ramping up to pre-trip output levels, followed by Genesee 2, which came back online at 5:12 p.m.

Between 5:08 p.m. and 5:14 p.m., the system controller was able to cancel all load shed directives and notified all wire owners to restore all load that was previously shed. With the cancellation of all load shed directives, the WECC Reliability Coordinator declared EEA2 at 5:14 p.m. Over the duration of the Event, the maximum load curtailed at a single point in time was 201 MW, representing approximately two per cent of total load in the province.

At 5:15 p.m., the Crossfield Energy Centre 2 generating unit was forced out of service, decreasing supply by approximately 40.7 MW. However, by this time, the return to service of other generating units had alleviated the supply shortfall enough that this forced outage did not require changes to EEA levels or any emergency steps. With the supply shortfall abating, the system controller notified the City of Red Deer to disengage their three per cent voltage reduction measures at 5:15 p.m.

At 5:41 p.m., the WECC Reliability Coordinator declared the system to be in EEA1 pursuant to the system controller's request. Keephills 1 and Crossfield Energy Centre 2 returned to service at 5:41 p.m. and 6:16 p.m., respectively.

With the return of Keephills 1 and Crossfield Energy Centre 2 generating units to service, upon the system controller's request, the WECC Reliability Coordinator declared EEA0 at 6:48 p.m., thereby ending the Event.

ANALYSIS AND RECOMMENDATIONS

The Event resulted from a number of contingencies occurring in a short period of time. It is standard operating procedure that after each contingency, or in the case of July 9 each generating unit outage, the system controller makes adjustments to prepare for the next contingency. During the event options to deal with the next contingency were reduced to shedding load to maintain the reliability of the entire AIES.

The AESO has conducted an internal review of the system controller's actions during the Event and has made the following findings.

NWPP Reserve

When the system controller made the first request for NWPP reserve, there was some confusion as to the quantity of NWPP reserve the AESO could request given the impact on the intertie line loading and the impact of the reserve on the Area Control Error (ACE) calculations. This resulted in an 11 minute delay in calling for the NWPP reserve from the time of the Genesee 2 trip. The delay did not impact the outcome of the event.

The AESO has made the following recommendations to remedy this issue:

- AESO personnel will take steps to further understand and document the impact of a NWPP reserve call on the ACE equation and reserve calculation.
- AESO personnel reviewed the available NWPP reserve point calculation against the reserve sharing group documentation. Supplemental system controller training on the NWPP reserve sharing program took place as planned on August 31, 2012.

Setting System Marginal Price (SMP)

As per Section 201.6 of the ISO Rules Pricing, SMP is to be set at $1000/MWh when the system controller directs the shedding of load. When the load curtailment directive was issued at 2:10 p.m., the system controller failed to set SMP at $1000 and SMP was left at the price cap of $999.99. However, this error was corrected retroactively and will not cause any errors in financial settlement. A price change from $999.99 to $1000 is a purely administrative signal that load has been shed and this error had no effect on the amount of available generation or on price-responsive load.

The AESO will document the steps for setting price to $1000/MWh in the Dispatch Tool application and these steps will be included in the system controller's supply shortfall procedures.

Load Shed Plans Review

When the AESO issues a load shed directive, each DFO's share of the load shed is determined using a pro-rata calculation. Each DFO must decrease their load by that amount according to their load shed plans. Section 202.2 states that load shed plans must consider factors such as appropriate priority of various loads, public safety, and technical requirements.

In reviewing the load shed which took place during the Event, the AESO has determined a need to review the load curtailment plans made by DFOs. The Event provided an excellent opportunity to see these plans in action and a review will help the AESO and DFOs to determine what future actions may be necessary regarding these plans.

Supply Shortfall Procedures Review

It is standard procedure for the AESO to review the supply shortfall procedures following a supply shortfall event and, if required, update ISO Rules and procedures to reflect the findings of that review. The AESO has begun a review of the procedures as contained in section 202.2 of the ISO Rules and in Information Document ID#2012-006(R) *Short Term Adequacy and Supply Shortfall*.

Power System Reliability

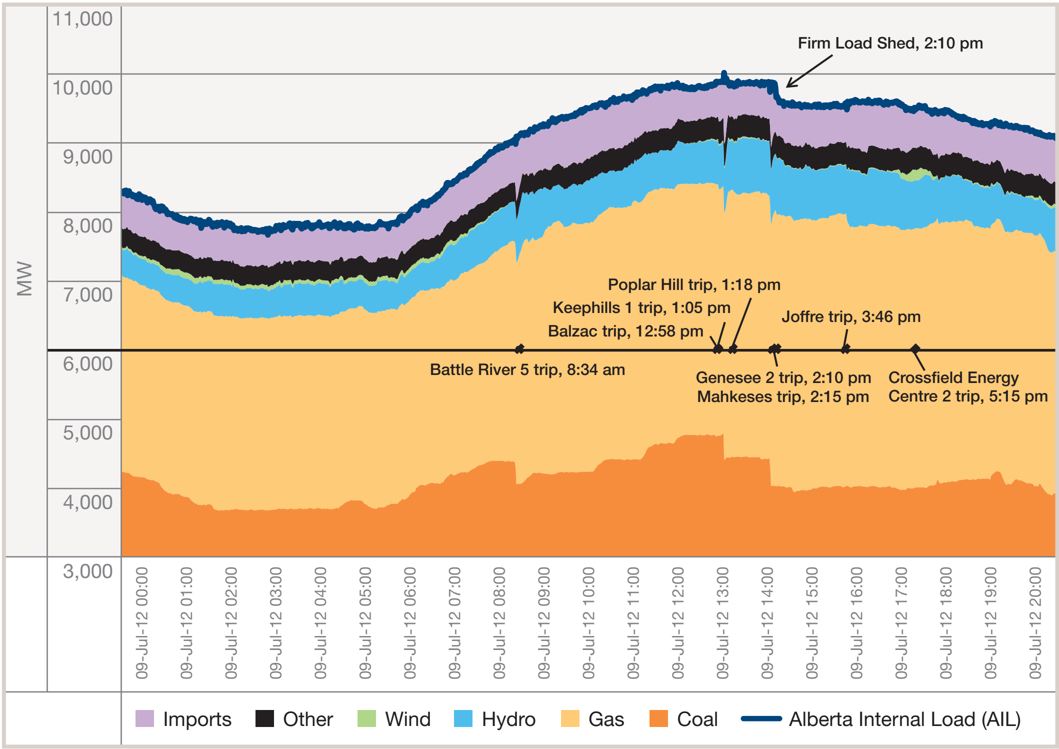
On July 9, 2012, in order to meet the Disturbance Control Standard following the trip of 400 MW from Genesee 2, the AESO issued directives to shed 201 MW of load across the province at 2:10 p.m. This EEA3 was caused by a supply shortfall due to ten generating unit forced outages that occurred up to that point in time coupled with high summer demand. At 3:51 p.m. the AESO issued a public appeal for Albertans to voluntarily reduce their power usage until adequate supply was restored to the AIES. Load restoration started at 3:39 p.m. and the EEAs were cancelled at 6:48 p.m.

Generating Units

Primary contributing factors to the Event were the planned and forced outages of eleven generating units throughout the day with a combined total capacity of 1,831 MW. The Sundance 3 generating unit had previously scheduled a planned outage, making 362 MW unavailable to the AIES. This outage was cancelled when it became apparent that the supply shortfall would take place and this generation was brought back online as quickly as possible. Battle River 5 tripped offline in the morning and was not able to come back online until after the Event. In addition to these outages, two large coal generating plants (Keephills 1 and Genesee 2) experienced trips during the hours of the Event. A trip occurs when mechanical, electrical or process failure causes a generating unit to cease to provide electricity and to separate through breaker action from the system. Additional trips at five gas generating plants (Balzac, Poplar Hill, Mahkeses, Joffre and Crossfield) throughout the day removed approximately 351 MW more from service.

Figure 2 below shows the total generation and load by fuel type on July 9, 2012. Dips in generation represent trips, which are shown on the time scale.

FIGURE 2
Generating Unit Trips and Generation Level by Fuel Type



Interties

B.C. Intertie

As discussed above, during supply shortfall conditions, the AESO curtails exports and can consider increasing power imported into Alberta by raising the import ATC and/or requesting emergency imports.

On July 9, 2012, the import ATC on the B.C. intertie was limited to 495 MW due to a planned outage of 2L113 line within the BC Hydro system. This outage was scheduled in accordance with ISO Rules, and was previously approved on June 26, 2012, when forecast conditions for July 9 did not indicate a high probability of a supply shortfall. In accordance with OPP 801, and consistent with ISO Rules, once a supply shortfall was anticipated, the planned outage was cancelled at 2:04 p.m. and import ATC on the B.C. intertie subsequently increased to 575 MW.

Saskatchewan Intertie

The import ATC on the Saskatchewan intertie was set to its maximum level of 150 MW; however, not all the import capability was utilized during the Event as no imports from Saskatchewan were available from market participants. Approximately 50 MW of capacity remained unused on the Saskatchewan intertie, even when Alberta requested and received 100 MW of emergency energy from SaskPower.

ANALYSIS AND RECOMMENDATIONS

In accordance with Alberta Reliability Standard EOP-004-AB-1, the AESO submitted a Preliminary Disturbance Report to WECC and the North American Electric Reliability Corporation (NERC) on July 11, 2012. WECC responded with their Preliminary Disturbance Report, which stated that no full or abbreviated report on the Event would be requested.

Also in accordance with EOP-004-AB-1, the AESO conducted a further detailed review of the Event and compiled an AIES Disturbance Report, which identifies the sequence of events that led up to the directive to shed load, the root causes of these events if available at the time of the report, and subsequently provides recommendations for corrective actions to alleviate power system reliability concerns.

While the Disturbance Report contains commercially sensitive information and cannot be made public, the key findings of the report are summarized below.

Generating Units

From January 1, 2008 to September 30, 2012, there were 88 days where three or more coal generating units were offline due to a forced outage within the same day. This means that the likelihood of a third coal unit tripping offline due to a forced outage during any day where two coal units are already offline (as occurred on July 9, 2012) is five per cent, making this a low-probability event.

Three major coal generating units and five gas generating plants tripped offline on July 9, 2012: Battle River 5, Keephills 1, Genesee 2, Balzac, Poplar Hill, Mahkeses, Joffre and Crossfield. In addition, one generating unit, Sundance 3, was on a planned outage. The MSA investigated these outages and stated that they "have not uncovered any breaches of the ISO Rules, Alberta Reliability Standards or anticompetitive conduct in violation of the *Electric Utilities Act*."[5] In addition to the MSA's findings, the AESO has not identified any instances of non-compliance to ISO Rules or Alberta Reliability Standards by GFOs during the Event.

[5] *http://albertamsa.ca/uploads/pdf/Archive/2012/Notice%20July%209%20121102.pdf*

A key purpose of the AIES Disturbance Report was to identify the specific reasons for the forced outages outlined in the Power System Reliability section of this report. The key findings of the ADR are summarized here:

High Ambient Temperature and Generating Unit Trips

Many of the generating unit trips were due to temperature-related issues such as temperature sensors and switches. Temperature sensors detect temperature and will cause a generating unit to trip when the temperature reaches levels that make operations unsafe for equipment, personnel, or the environment.

Discussions with generating facility owners confirmed that high ambient temperature conditions were a factor in many of these temperature-related trips. High ambient temperatures can cause generating units to trip if sensors and switches are not properly maintained. For example, the temperature switch settings on generating units can drift or be set incorrectly, causing generating unit trips and resulting outages.

The AESO has determined that GFOs should review their maintenance practices, procedures and quality control programs on temperature sensors and switches that could lead to a generating unit trip. The AESO plans to request that all GFOs conduct this review and report back to the AESO when the review is complete.

High Ambient Temperature and Reduced Generation Capability

In addition to the above outages, many generating units experienced what might be termed as unplanned derates (reduction in generation output) to their available capability. Discussions with some of the GFOs indicated that the reduced capability was due to high ambient temperatures.

The AESO plans to work with generating facility owners to ensure AESO personnel understand this occurrence. The AESO will also determine whether this occurrence is appropriately considered in the AESO's operations, forecasting and adequacy assessments.

Interties

B.C. Intertie

As noted above, the import capability on the B.C. intertie was set to 575 MW during the Event after the AESO cancelled a planned outage of 2L113 line. Although 575 MW does not represent the full import capability of the B.C. intertie and there was more than 575 MW available for import from B.C., this capability was established based on two significant factors, lack of offers for Load Shed Service for imports (LSSi), and lightning risk on the B.C. intertie.

The AESO uses LSSi to increase the import ATC on the B.C. intertie above levels which would otherwise be possible. LSSi service is provided by consumers of electricity in Alberta who agree to instantaneously reduce their demand in response to direction from the AESO. LSSi providers submit offers to the AESO. When additional intertie capability is needed, the AESO instructs LSSi providers to arm their load, which will then be tripped off if imports trip and frequency goes outside acceptable ranges.

During the Event, there were 50 to 70 MW of LSSi offered by consumers. Section 303.1 of the ISO Rules *Import Load Remedial Action Scheme Service and Load Shed Service* indicates that when Alberta Internal Load (which refers to the demand, expressed in megawatts, served by generation at any single point in time) is greater than 8,400 MW and LSSi offers are between 55 and 110 MW, import ATC is limited to 575 MW. Due to the limited availability of LSSi, imports on the B.C. intertie had to be constrained to 575 MW.

According to OPP 801, the AESO could consider increasing import ATC beyond the level allowed by LSSi offers, but another factor in the limited import capability on the B.C. intertie on July 9 was lightning in the B.C. intertie area and with a significant risk of a lightning strike on one of the lines that form the B.C. intertie. With generating units running at high levels to alleviate the supply shortfall, if this line had tripped due to a lightning strike, there was a risk that the overall reliability of the AIES would be compromised. This limited import capability ensured that the intertie operated at a level that was the most reliable to the AIES. The province's previous load shed event (July 24, 2006) was precipitated by a lightning strike that tripped the B.C. intertie.

The AESO will identify whether any changes should be made to further clarify the AESO's role in operating the interties during a supply shortfall condition while ensuring safe and reliable operation of the AIES. This will include a review of LSSi policies and procedures to determine whether improvements can be made to the arming of LSSi.

Saskatchewan Intertie

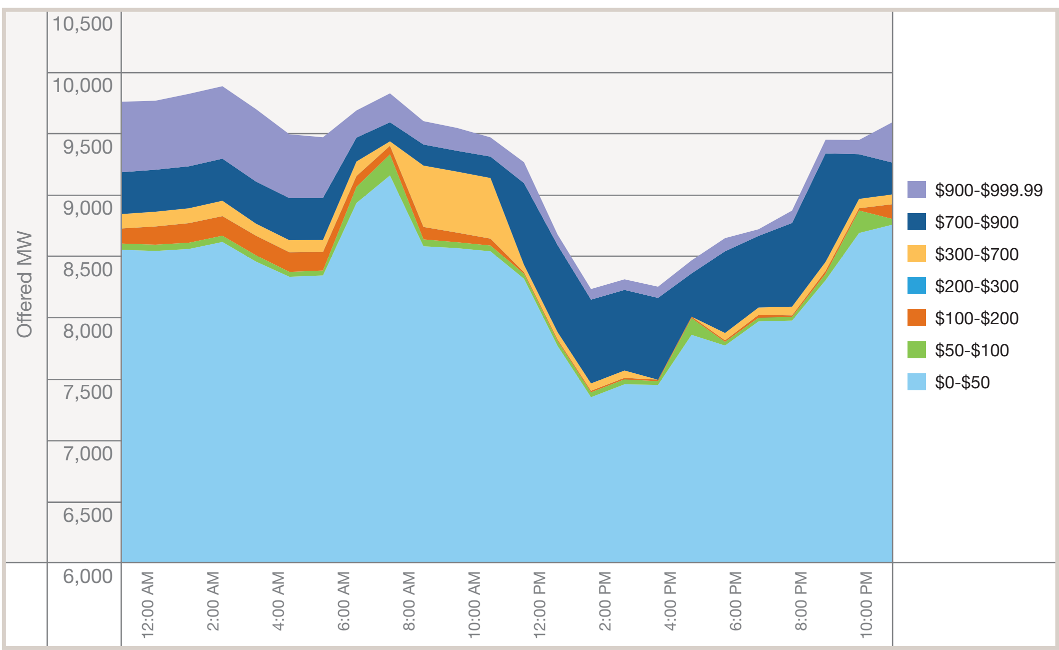
As noted above, the import capability on the Saskatchewan intertie was not fully utilized during the Event despite the ATC being set at its maximum level of 150 MW. One reason for the underutilization of the Saskatchewan intertie was that a similar shortage of energy was occurring in Saskatchewan during the hours of the Event due to hot weather, and therefore high electricity demand in that province. Because of that shortage in Saskatchewan, SaskPower was only able to provide 100 MW of emergency energy.

Market Impacts

As discussed above, market participants offer their electricity into the wholesale market for a given price between $0/MWh and $999.99/MWh and all offers are stacked in order of ascending price to create the merit order.

Figure 2 below shows the total MW offered at the 30th minute of each hour in the merit order, aggregated by price band. As seen in the figure, July 9, 2012 saw a dramatic decline in total offered MW to the market, due to the planned and forced generating unit outages that occurred throughout the day. In particular, the MW offered in the $0-$50 block saw the most dramatic reduction during the Event due to various large baseload generating units tripping offline due to forced outages.

FIGURE 2
MW Offers



During the Event, all supply in the market was dispatched, sending the pool price up to the maximum offer value of $999.99/MWh. Section 201.6 3(1) (b) of the ISO Rules states that when the system controller directs an involuntary curtailment of load (i.e., when demand exceeds all available supply) SMP will be set at $1,000/MWh. This indicates that out-of-market measures have been taken to balance supply and demand and that the SMP is no longer being set by assets in the merit order. During the event, the system controller issued directives to curtail load at 2:10 p.m. and shortly afterward posted the SMP at $1,000/MWh. The SMP remained at $1,000/MWh from 2:10 p.m. to 5:09 p.m. For more information on the actions of the system controller during the event, see the System Controller Action section of this report.

The AESO prepares a number of reports and forecasts to assist in managing the AIES. The following reports and forecasts are used by the AESO in its daily operation of the market and were taken into consideration preceding and during the Event.

Load Forecast

The AESO forecasts day-ahead system demand for each hour. The day-ahead load forecast uses historical demand patterns, sunlight variables, calendar/holiday variables, and temperature information to forecast electricity demand for the following day. The day-ahead load forecast value serves as an input into the Supply Adequacy report (see below).

On July 9, 2012, the day-ahead load forecast predicted a peak load of 9,829 MW for the hour between 2:00 p.m. and 3:00 p.m., indicating a new record would be set for summer peak demand. As the day progressed, the load forecast predicted 9,891 MW for the hours between 12:00 p.m. and 2 p.m. with a peak of 9,913 MW for the hour between 2:00 p.m. and 3:00 p.m. Peak demand for the day of 9,885 MW occurred in the hour between 1:00 p.m. and 2:00 p.m., after price-responsive load had turned off and the system controller directed a load shed of 201 MW. This indicates that peak load could have been much higher and closer to the forecast value if baseload generation had been available to meet demand. Temperature was a significant factor in this peak demand, as had been anticipated in the load forecast.

Wind Power Forecast

The AESO provides a wind power forecast twelve hours ahead that uses near real-time meteorological data gathered at wind power sites to indicate the amount of wind power that will be available to the AIES in the next 12 hours. The report is updated every ten minutes.

On the day of the Event the wind power forecast (forecasting 180 minutes out) indicated that wind power would be fairly low during the hours of the Event (1:00 p.m. – 7:00 p.m.), ranging from 20 to 40 MW. During the Event, wind power ranged from a low of 9 MW to a high of 95 MW for a short period between 5:00 p.m. and 6:00 p.m. The daily capacity factor for wind power (wind power produced as a percentage of total installed wind capacity) averaged four per cent, compared to the 2012 year-to-date average capacity factor of approximately 30 per cent.

Supply Adequacy

The Supply Adequacy report is a forecast of the remaining MW in the merit order for the current day and the following six days, using the STA calculation set out in ID#2012-006(R). This report forecasts the amount of offer volume remaining in the merit order above that needed to meet demand. The day-ahead load forecast is used as input in the Supply Adequacy report to give an approximation of the load shape for the day. Another input into the Supply Adequacy report is the stated available capability of each generating unit, which takes into account any derates and outages. The Supply Adequacy report is updated approximately every five minutes to reflect the current MW load level and changes to any other factors used in the calculation. This combination of load shape from the day-ahead load forecast and current load level allows the AESO to more accurately determine future load and determine whether a supply shortfall is anticipated.

The STA calculation also takes forecast wind power into account. The calculation, looking out the next six hours, uses a value based on the current level of wind and historical patterns of wind power, using the wind power forecast as an input. These values are then adjusted for predetermined risk levels. On July 9, 2012, the calculation for the time frame beyond the next six hours used a fixed value of 145 MW for wind power. This is based on historical data available when the STA calculation was formalized in the ISO Rules. The STA calculation has since been updated and now uses the AESO's wind forecast rather than the fixed value of 145 MW.

In the days leading up to the Event, there was no indication that a supply shortfall event would take place on July 9, 2012. The Supply Adequacy report began to forecast the supply shortfall situation at 1:13 p.m. on July 9, after the Keephills 1 generating unit was forced out of service at 1:06 p.m. and the inputs into the Supply Adequacy report changed to reflect this. Likewise, as the generating units returned to service the Supply Adequacy report reflected the increase in supply and indicated that sufficient supply would be available at 6:13 p.m. This aligns with the actual timeline, as the WECC Reliability Coordinator declared EEA0 at 6:48 p.m.

ANALYSIS AND RECOMMENDATIONS

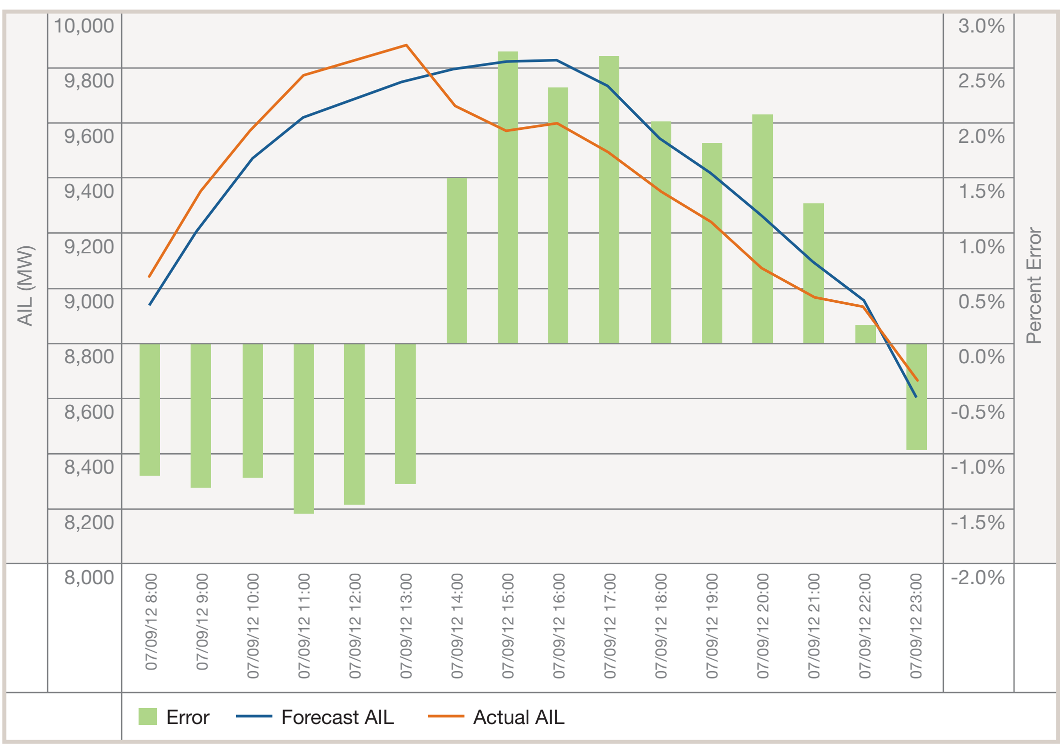
The AESO has conducted analysis on the reports and forecasts that relate to supply shortfall events including the load forecast, the wind power forecast and the Supply Adequacy report. This analysis was conducted to determine their accuracy and whether any inaccuracies in the reports contributed to the Event.

Overall, the analysis shown indicates that the Event was not caused by inaccuracies in the AESO's various forecasts and reports. The AESO is continuously making improvements to forecasts and reports to make them as accurate as possible.

Load Forecast

Figure 4 below shows the AESO's day-ahead load forecast compared to actual load levels on July 9, 2012. Prior to the shedding of load, the forecast underestimated actual load levels by approximately 1.5 per cent. After 2:00 p.m., price-responsive load had turned off and the AESO directed a load shed of 201 MW. As a result, the highest demand for the day reached 9,885 MW between 1:00 p.m. and 2:00 p.m. This load shed, as well as calling for public reductions in demand, resulted in actual load dropping below what was forecast for the remainder of the day. Curtailing load, calling for public reductions, and price responsive load all have a significant effect on load values and are difficult to account for in the load forecast. In general, in 2012 the day-ahead load forecast was within one per cent of actual load levels.

FIGURE 3
Day Ahead Load Forecast compared to Actuals from the July 9, 2012 Supply Adequacy Report

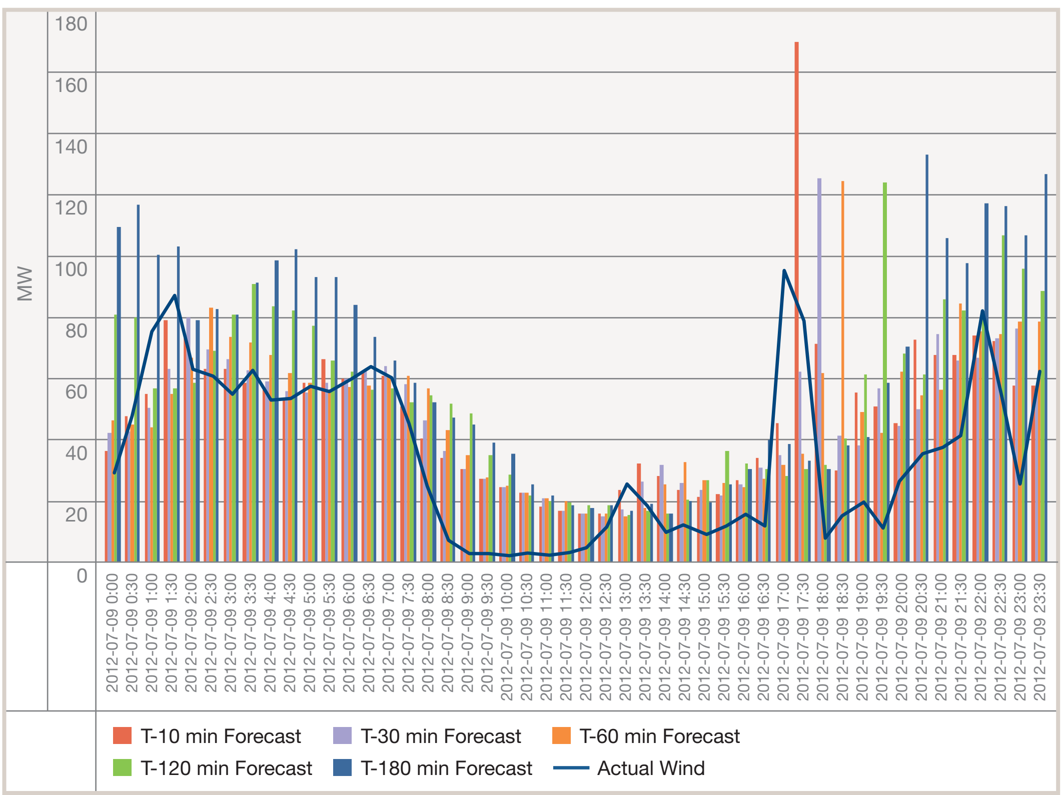


The analysis shown above indicates that the AESO's load forecast was reasonably accurate for July 9, 2012. The day-ahead load forecast indicated record high levels for July 9, 2012, and the Event was caused by insufficient supply to meet these levels as generating units became unavailable, indicating that the Event was not caused by inaccuracies in the forecast. The AESO does not intend to make any changes to the day-ahead load forecast as a result of the Event.

Wind Power Forecast

Figure 5 below compares wind power forecasts from different timeframes (from three hours prior to ten minutes prior) for a given time to the actual wind power level at that point in time. As seen in the graph, the wind power forecast predicted the general shape of wind power on July 9, 2012. However, the forecast did not accurately capture the actual minimum wind output level, as actual wind reached a minimum of 1 MW during the day, while the minimum wind power forecast was approximately 16 MW.

FIGURE 4
Forecast and Actual Wind Power Production on July 9, 2012



As discussed above, the wind power forecast for July 9, 2012 was reasonably accurate in predicting the overall shape of wind generation throughout the day; however, the forecast may at times fail to accurately capture extreme minimum and maximum levels of wind power. The AESO is currently working with the wind power forecast service provider to make improvements to this forecast.

Supply Adequacy

As discussed above, the Supply Adequacy report gave no indication of a supply shortfall until approximately an hour before the system controller directed the shedding of load. Due to the sudden and unexpected nature of multiple large generating units being forced offline, the Supply Adequacy report would not have been able to predict this type of shortfall event in advance. The Supply Adequacy report correctly factored in high demand for the day, but did not show a shortage of supply until multiple large baseload generating units tripped off and dramatically reduced the energy supply.

Overall, the Supply Adequacy report functioned as expected during the Event; however, the AESO is conducting a review of the STA calculation and the assumptions behind it to determine whether any improvements can be made.

Photo courtesy of AltaLink.

Communication

Industry Communication

The AESO's internal emergency procedures state that during a business disruption, email communication to the Industry Crisis Communication Contact List is to be supported by use of the Ventriloquist system, an automatic voice messaging system which sends one voicemail to all members of this list. The intent of the voice message is to inform industry participants of a business disruption through alternate communication channels and advise them to check their email and the Industry Phone Line to receive ongoing updates. A business disruption message is also recorded on the Industry Phone Line and updated as the status of the business disruption changes. The Industry Phone Line is only available to those on the Industry Crisis Communication Contact List.

Corporate Communication protocol outlined in the Crisis Communication Plan is to notify the existing Industry Crisis Communication Contact List of EEAs during a supply shortfall event. The practice at the time of the Event was to alert the industry participants on this list via email as soon as possible after EEA2 is declared and again after EEA3 is declared, as well as at every subsequent change to the EEA level until the system returns to normal.

During the event of July 9, 2012, the AIES experienced conditions for declaring EEA2 at 2:06 p.m. and less than five minutes later, at 2:10 p.m., the AIES entered EEA3. Corporate Communication sent the first email to the Industry Crisis Communication Contact List at 4:16 p.m. This email advised industry participants of the effective time of the EEA3 and also contained the text of the public appeal which was distributed to the media at 3:51 p.m. Subsequent emails informed these recipients of the changes in EEA levels from EEA2 to EEA1 and EEA0 as the Event ended.

Public Communication

Part of the AESO's Crisis Communication plan is to consider issuing a public appeal asking Albertans to voluntarily cut back electricity use if the conditions of the supply shortfall event warrant such an appeal. On July 9, 2012 the AESO issued an appeal at 3:51 p.m. through Marketwire, the AESO's news release distribution service. The appeal remained a valid request until the system reverted to EEA1 at 5:41 p.m.

OPP 801 stated that the AESO will "consider a public appeal if conditions warrant it". Because the Event was characterized by unexpected generating unit outages, the AESO did not initially expect conditions to warrant a public appeal; this changed as the Event unfolded and the public appeal was issued at 3:51 p.m.

During the Event, the AESO directed distribution facility owners to shed specific amounts of load, as discussed above. When the AESO directs the shedding of load, affected DFOs are then responsible for communicating the specific impacts to their customers.

ANALYSIS AND RECOMMENDATIONS

Industry Communication

The AESO informs its Industry Crisis Communication Contact List of EEA levels. During the event of July 9, 2012, EEA3 was declared less than five minutes after AIES conditions met those described by an EEA2. Given this limited timeframe, it would have been impossible for the AESO to have given notice of the EEA3 prior to the AESO issuing a directive to shed load.

A news release was ready for distribution at 2:54 p.m., however, at 3:04 p.m., the AESO was advised that Sundance #3 may have been close to coming back on line and the AESO may not need to issue the public appeal. The AESO sent the first email to the Industry Crisis Communication Contact List at 4:16 p.m. Subsequent emails informed these recipients of the changes in Emergency Energy Alert levels from EEA2 to EEA1 and EEA0 as the Event ended. The time it took to for this initial external communication was affected by the combination of a number of factors:

- Internal process issues were encountered with respect to communicating with the Industry Crisis Communication Contact List.
- A supplier side malfunction of the voicemail broadcast system occurred, preventing use of this telephone system to alert the Industry Crisis Communication Contact List when the system was in EEA3. As a result, the Industry List did not receive voicemail communication. This malfunction was not discovered as it is only possible to test the system up to the point before a message is sent and emergency drills are only performed up to this point to prevent confusion among market participants and AESO employees. This malfunction was caused when the service was migrated to a new platform by the supplier and the AESO was not notified.
- In addition, the Industry Crisis Communication Phone Line, a further channel of industry communication to inform industry participants of Energy Emergency Alert levels did not work due to a change initiated by the supplier. Follow-up by the AESO revealed that the change information had not reached the appropriate contact within the AESO.

The AESO has implemented the following changes to its internal processes and protocols to improve the AESO's industry communication during supply shortfall events:

- Protocol changes have been made to ensure that emails will be sent to the Industry Crisis Communication Contact List at EEA1 and each subsequent level up and down the Energy Emergency Alert scale.
- The Industry Crisis Communication Contact List is now readily available to all AESO Communication staff and is updated monthly rather than quarterly.
- Supplier issues with the Ventriloquist system and the Industry Phone Line have been rectified. These systems have been tested and will be tested on a monthly basis to avoid future malfunctions.
- Plans are in progress to convene a meeting of industry communicators to review roles, responsibilities and potential for improvements.
- Process changes have been documented and reviewed with the responsible staff.
- The use of Ventriloquist and the phone line will be assessed based on the severity of each situation. The AESO recognizes that technology has changed and the use of email has superseded telephone as an effective means of communication.
- The AESO continues to explore opportunities for improvement.

Public Communication

ISO Rules and the AESO's Crisis Communication plan state that a public appeal should be considered when the AESO believes that a public appeal will be effective in managing the supply shortfall event. Appealing to the public when the system is in EEA1 would involve more frequent appeals with the potential of undermining effectiveness through overuse.

The AESO issued a public appeal for energy conservation during the Event. This appeal was released at 3:51 p.m. through Marketwire, the AESO's news release distribution service. OPP 801 stated that the AESO will "consider a public appeal if conditions warrant it". The speed at which the Event unfolded resulted in the public appeal being issued after the load shed directive was issued by the system controller. However, the appeal remained a valid request until the AIES reverted to EEA1 at 5:41 p.m.

Upon review of the AESO's actions in response to the Event, the AESO has made changes to its internal policies and processes for timelier communication to the public. The AESO entered EEA3 at approximately 2:10 p.m. and the public appeal for energy conservation was issued at 3:51 p.m.

Historically, because of the large amount of industrial demand in Alberta, public appeals for reduced energy usage have not resulted in large decreases in demand, and the AESO may implement other steps to alleviate the supply shortfall condition before issuing a public appeal. However, for cases where a public appeal is deemed to be effective, the AESO has implemented changes to its internal processes and protocols to improve the AESO's public communication.

During the Event, the AESO directed DFOs to shed specific amounts of load, as discussed above. When the AESO directs the shedding of load, affected DFOs are then responsible for communicating the specific impacts to their customers.

The AESO plans to convene a meeting of industry communicators to review roles, responsibilities and improvements. The purpose of the meeting will be to encourage dialogue about how the AESO and industry participants will meet the needs of Albertans and coordinate the approach to communications where appropriate in crisis situations.

After the Event, the Alberta Emergency Management Agency (AEMA) expressed their concern that they were not contacted when the load curtailment directive was issued as the AEMA is not included in the Industry Crisis Communication List. The AEMA leads the coordination, collaboration and co-operation of all organizations involved in the prevention, preparedness and response to disasters and emergencies. In response to concerns expressed by the AEMA, meetings were held between the AESO, the Department of Energy and the AEMA to discuss communications during emergency operations. As a result, it was confirmed that the AEMA does not have a role in restoration management, and therefore does not need to be included in the Industry Crisis Communication List.

Relevant Authoritative Documents

The specific procedures and requirements for managing a supply shortfall event are contained in fourteen authoritative documents summarized in the table below, followed by the AESO's assessment of self-compliance with that authoritative document. This table contains the authoritative documents that were in place on July 9, 2012. Some have been removed or replaced since that date. See Appendix 2 for copies of all the authoritative documents listed below.

ANALYSIS AND RECOMMENDATIONS

In the review of these authoritative documents, the AESO was in compliance with all requirements except one requirement contained within OPP 802. OPP 802 required the AESO to notify certain parties of load shedding and emergency alerts by telephone. The Medicine Hat Electric Control Center was notified by email of the emergency alert, however was not notified by telephone. There was no work scheduled on the City of Medicine Hat system/AIES interface that day that would have needed to be cancelled, and therefore it did not impact the Event. The AESO self-reported this contravention to the MSA. The AESO has mitigated the issue, and the MSA has determined that no further action is required in pursuing the contravention. The MSA has closed this file.

Authoritative Document	Summary	Compliant? (Yes/No)
Section 301.2 *ISO Directives*	Section 301.2 grants the AESO the authority to issue directives to market participants and requires market participants to comply with directives	Yes
Section 6.3.7* *Supply Shortfall Directive*	Section 6.3.7 obligated the AESO to follow supply shortfall procedures if the forecasted AIES demand exceeds the available supply	Yes
Section 6.8* *Involuntary Load Curtailment*	Section 6.8 obligated the AESO to calculate pro-rata shares of any load curtailment between distribution facility owners and sets out areas of consideration for each distribution facility owner's load curtailment plan	Yes
EOP-002-AB-2 *Capacity and Energy Emergencies*	EOP-002-AB-2 obligates the AESO to plan for supply shortfall and other emergency events, and to follow these plans and use specific procedures to alleviate supply shortfall events	Yes
EOP-003-AB-1 *Load Shedding Plans*	EOP-003-AB-1 obligates the AESO to issue directives for the shedding of load when all other remedial steps have been taken	Yes

* *Content relocated to Section 202.2 as of January 8, 2013*

Authoritative Document	Summary	Compliant? (Yes/No)
EOP-004-AB-1 *Disturbance Reporting*	EOP-004-AB-1 obligates the AESO to submit disturbance reports after events which jeopardize the operation of the bulk transmission system, in order to study these events and minimize the likelihood of future occurrences	Yes
OPP 401 *Regulating Reserve Service*	OPP 401 defines policy and procedures for the AESO in dispatching regulating reserve	Yes
OPP 402 *Supplemental and Spinning Reserve Services*	OPP 402 defines the contingency reserve criteria for the AIES and provides requirements for the AESO in issuing dispatches and directives for supplemental and spinning reserve	Yes
OPP 404 *Ancillary Services Dispatches & Directives*	OPP 404 defines policy and procedures for the AESO and market participants in the exchange of ancillary service dispatch and directive messages and responses	Yes
OPP 705* *Short Term Adequacy Assessments*	OPP 705 set out the short-term adequacy (STA) calculation and obligates the AESO to perform STA assessments	Yes
OPP 801* *Supply Shortfall*	OPP 801 prescribed procedures for the AESO in managing supply shortfall events	Yes
OPP 802** *Energy Emergency Alerts and Firm Load Directives*	OPP 802 obligated the AESO to issue emergency energy alerts and load directives	No***
OPP 1304 *System Event Monitoring and Disturbance Reporting* and OPP 1305 *WECC Reliability Management and Related Reporting*	OPPs 1304 and 1305 obligate the AESO to report AIES system disturbances and to submit reports to NERC and WECC	Yes

* *Content relocated to Section 202.2 as of January 8, 2013*

** *Content relocated to Section 305.1 of the ISO Rules Energy and Emergency Alerts as of October 31, 2012 and to Section 202.2 as of January 8, 2013*

*** *A minor inconsequential step in OPP 802 was missed. However, the MSA extended forbearance on this non-compliance incident.*

Summary of Conclusions and Recommendations

The central finding of all the analysis conducted by the AESO is that the supply shortfall event was a sudden and low-probability event caused by a combination of several normally inconsequential factors. None of these single factors would have caused the event by itself. The Event was managed appropriately and system reliability was maintained.

The AESO has identified areas for improvement in the management of supply shortfall events and other more general process changes. The AESO continuously seeks ways to better fulfill its legislated mandate to provide for the safe, reliable and efficient operation of the AIES. The Event tested the application of the AESO's practices and procedures. The Event was handled in an effective manner particularly given its unexpected nature. However, since supply shortfall events are rare, any occasion when these emergency practices and procedures are put into action is a valuable opportunity to identify possible improvements for the AESO and market participants.

For convenience, the table below summarizes the AESO's recommendations at a high level. See the relevant sections throughout this report for details on these recommendations.

Recommendation	Expected Timeline
The AESO will conduct an in-depth review of supply shortfall procedures in Section 202.2 of the ISO Rules and ID#2012-006(R) to determine the relative effectiveness of various steps	Initiated Q1 2013
The AESO will request all GFOs to conduct a review of maintenance practices, procedures and quality control programs on temperature sensors and switches	Completed by Q2 2013
The AESO will work with GFOs to better understand the effect of ambient temperature on available capability levels and determine whether it is appropriately considered in market operations, forecasting and long-term adequacy assessment	Completed by Q4 2013
The AESO will review Supply Adequacy metrics for potential improvements	Completed by Q2 2013
The AESO will review DFOs' load shed plans to further understand the shedding of load within the AIES and determine whether future related revisions to ISO Rules may be appropriate	Initiated Q1 2013
The AESO will review use of interties during supply shortfall situations, including a review of LSSi policies and procedures to determine whether improvements can be made to the arming of LSSi	Initiated Q1 2013
The AESO will implement various process changes for timely, relevant communication to market participants and the public	Completed Q4 2012
The AESO will convene a meeting of industry communicators to review roles, responsibilities, and possible improvements to communication of emergency events	Completed by Q2 2013
The AESO will issue updates periodically on the progress of these recommendations	Completed by Q4 2013

Appendix 1:
Compliance with Authoritative Documents

Throughout this report, ISO authoritative documents are referenced as they existed on July 9, 2012. Since that date, many of these authoritative documents have been transitioned into the new ISO Rules framework. For ease of reference, any documents which are no longer in effect are indicated by including the title of the replacement document in brackets.

Section 301.2 ISO Directives

As required by Section 301.2 of the ISO Rules, the ISO may issue a directive to a market participant, including a directive to:

- Increase or decrease the real power or reactive power output, or both, from a facility;
- Shut down or start up a facility; or
- Switch transmission system elements, alter planned outage or maintenance schedules, or load shed.

The ISO may issue a directive verbally, electronically or in writing. On July 9, the AESO issued a variety of directives during the Event including directives to cancel outages, reduce voltage, curtail and restore load. All of the directives issued were within the parameters of Section 301.2 of the ISO Rules and there are voice recordings and shift logs as supportive evidence. There were no recorded instances of directives being refused or rejected by market participants within either the voice logs or the shift logs.

Rule 6.3.7 Supply Shortfall Directive (Equivalent requirements now contained in Section 202.2 Short Term Adequacy and Supply Shortfall)

Rule 6.3.7 required that if during the trading day the system controller determines that the forecast AIES demand requirement exceeds the available supply in any settlement interval, the system controller will use ISO supply shortfall operating policies and procedures to issue directives as required. The AESO did use supply shortfall operating policies and procedures to issue directives. Supply Shortfall procedures were outlined in OPP 801 *Supply Shortfall* with reference to OPP 802 *Firm Load Directives Procedures*. Compliance with OPP 801 and OPP 802 is described in detail later in this report.

Rule 6.8 Involuntary Load Curtailment (Equivalent requirements now contained in Section 202.2 Short Term Adequacy and Supply Shortfall)

Rule 6.8 set out the legal obligation for distribution facility owners to shed load when so directed by the system controller. It also requires the AESO to determine each DFO's share of the load shed using a pro-rata calculation. Section 6.8 also outlined areas of consideration for each distribution facility's load curtailment plan, and requires that plans for the shedding of load take into account factors such as appropriate load priority, public safety, operating limit violations, and the need to maintain integrity of remedial action schemes and under frequency load shed schemes.

The AESO determined shares of load shed using a pro-rata calculation and was in compliance with Section 6.8.

EOP-002-AB-2 Capacity and Energy Emergencies

The purpose of Alberta Reliability Standard EOP-002-AB-2 *Capacity and Energy Emergencies* is to ensure the AESO is prepared for a supply shortfall event. EOP-002-AB-2 comprises nine requirements, all of which are applicable to the ISO.

R1 states the ISO must exercise its authority to alleviate a supply shortfall event to the AIES. During the Event, the AESO was compliant with this requirement. An authorization letter exists as set out in the MR1 of EOP-002-AB-2 (measurement for R1) and establishes the authority of the system controller, job descriptions for the system controller's reference, Operating Policies and Procedures, reliability criteria and NERC and WECC standards.

R2 requires that the ISO must implement its capacity and energy emergency plan by following ISO Rules. The AESO was compliant with its procedures to manage supply shortfall. Supply shortfall procedures are outlined in OPP 801 with reference to OPP 802. Compliance with OPP 801 and OPP 802 is described in detail within their respective sections in this report.

The AESO maintained compliance with R3 of EOP-002-AB-2 by communicating its current and its forecast of future system conditions to the WECC Reliability Coordinator, WECC, and Alberta's adjacent balancing authorities, B.C. and Saskatchewan. Voice records exist as evidence of this communication.

R4 states the ISO must follow plans in ISO Rules when it anticipates a supply shortfall event may occur. The ISO plans must include any one of or combination of the following:

- Issuing directives as necessary, including bringing on all available generation;
- Postponing equipment maintenance; and
- Posting interconnection Total Transfer Capability (TTC) to maximum reliability based capacity and being prepared to reduce load.

The following steps within Table 1 of OPP 801 address compliance with the points listed above:

- Step 2 (issuing directives to bring on available generation);
- Step 10 (cancel maintenance); and
- Step 5 (maximize TTC/ATC).

A detailed analysis of compliance with OPP 801 can be found below. No preparations were made for the supply shortfall as a supply shortfall was not anticipated.

R5 requires that during a supply shortfall event the ISO must:

- Only use the assistance provided by the Interconnection's frequency bias for the time needed to manage the event.
- Not direct generating units in an attempt to return the Interconnection frequency to normal beyond that supplied through frequency bias action and interchange schedule changes.

The AESO maintained compliance with R5. AGC was in Tie Line Bias mode throughout the event, therefore the AESO only used the assistance provided by the interconnection's frequency bias.

The AESO complied with the control performance and disturbance control standards during a supply shortfall event as per R6. As the remedies laid out within R6 are also included within Table 1 of OPP 801, the details of compliance with R6 are not included here. For details regarding a specific remedy in R6, the table below lists the R6 remedies with the relevant steps from OPP 801 and the compliance details for these steps can be found in the detailed subsection on OPP 801 on the following page.

R6 Remedy	Related Steps from OPP 801 Table 1
Loading all available generating capacity	**Step 3** Ancillary Services Assets Dispatched **Step 18** (17 on working copy) MAM Energy Released
Deploying all available operating reserve	**Step 12** Issue Directives for Excess Contingency Reserves **Step 19** Direct Internal Ancillary Services for Supplemental and Excess Spinning Reserves **Step 26 and 27** Dispatch On External Reserves and Direct External Supplemental and Spinning Reserves **Step 28** Issue Ancillary Service Directives for Spinning Reserves and Request EEA2
Interrupting interruptible load and exports	**Step 7** Curtail One Hour DOS **Step 8** Curtail Seven Minute DOS **Step 9** Curtail Standard DOS **Step 23** Dispatch Voluntary Curtailment Program **Step 6** Reduce Export ATC to Zero
Requesting emergency assistance from other balancing authorities	**Step 26** On working copy – Request NWPP Reserve Sharing **Step 29** Request Emergency Energy from BCTC and SaskPower
Requesting, in accordance with ISO Rules, the WECC Reliability Coordinator to declare an Energy Emergency Alert(s)	**Step 14** (b and c) Request and Issue EEA1 **Step 28** Issue Ancillary Service Directives for Spinning Reserves and Request EEA2 **Step 30** Issue Firm Load Directives
Reducing load, through procedures such as public appeals, voltage reductions, and curtailing interruptible loads	**Step 2** Planning Steps **Step 14** (d) AESO Ops On-call notify Stakeholder Relations and Communication **Step 17** 3% Voltage Reduction

R7 requires that if all of the remedies listed in R6 have been implemented and the control performance and disturbance control standards are not being met, the ISO must issue directives for the manual shedding of load without delay in order to return its Area Control Error to zero and, in accordance with the ISO Rules, request the WECC Reliability Coordinator to declare an Energy Emergency Alert. These sub requirements are also reflected within Step 28 and Step 30a respectively, of Table 1 in OPP 801. The AESO was compliant with R7. A detailed analysis of this compliance is below in the subsection on OPP 801.
In accordance with R8, the AESO notified the WECC Reliability Coordinator and adjacent balancing authorities in the WECC that a supply shortfall event existed before revising AIES operating limits. The procedure for notifying the WECC Reliability Coordinator of a supply shortfall event is contained in Step 14b (EEA1), Step 25a (EEA2), Step 28a (EEA3) of Table 1 in OPP 801. The procedure for notifying the adjacent balancing authority in the WECC (British Columbia) of a supply shortfall event is contained in Step 14c of Table 1 in OPP 801 (Table 2 in OPP 802 contains a list of specific entities to be contacted).

The AESO completed the EEA3 report and submitted it to the WECC Reliability Coordinator within two business days of termination of the EEA3, maintaining compliance with R9. The AESO was compliant with EOP-002-AB-2.

EOP-003-AB-1 Load Shedding Plans

The purpose of Alberta Reliability Standard EOP-003-AB-1 *Load Shedding Plans* is to ensure plans are in place and implemented to shed load when there is insufficient generation or transmission capacity, to mitigate the risk of an uncontrolled failure of the interconnection.

As per R1 of this standard, the AESO issued directives to shed load after considering all remedial steps. These directives can be confirmed through voice recordings and logs. R2 through R8 were not directly required during the Event; therefore this report will not contain detailed analysis of these requirements. The AESO was in compliance with R9 and R10, respectively, by having procedures in effect for directing operator controlled manual load shedding to respond to real-time emergencies, and by following these procedures during the Event. R11 of EOP-003-AB-1 is only applicable to demand customers and wire service providers. The AESO was compliant with EOP-003-AB-1.

EOP-004-AB-1 Disturbance Reporting

The purpose of Alberta Reliability Standard EOP-004-AB-1 *Disturbance Reporting* is to ensure that events which jeopardize the operation of the bulk electric system, or which result in system equipment damage or customer interruptions, are studied and understood to minimize the likelihood of similar events in the future. EOP-004-AB-1 also ensures that disturbances and unusual occurrences are reported to WECC and NERC.

In accordance with R1 of EOP-004-AB-1, the AESO determined that the Event required a preliminary disturbance report as per Appendix 1 in EOP-004-AB-1. Appendix 1 requires a preliminary disturbance report in the event of equipment failures/system operational actions which result in the loss of 300 MW of demand for more than 15 minutes and when load of 100 MW or more is shed to maintain continuity of the bulk electric system. During the Event, equipment failures resulted in the loss of approximately 1,100 MW and load shedding of 201 MW.

As required under R2 of EOP-004-AB-1, the AESO analyzed the events of July 9, 2012 in accordance with OPP 1304. For details on the results of this analysis see the section on OPP 1304 on the following page.

In compliance with R2 of EOP-004-AB-1, the AESO completed and filed a preliminary disturbance report to NERC and WECC. No further information or reporting was requested by WECC.

R3 is a requirement for TFOs and GFOs and is therefore not applicable to the AESO.

R4 requires that the ISO provide an "Interconnection Reliability Operating Limit and Preliminary Disturbance Report", as included in Appendix 1 of EOP-004-AB-1, to WECC and NERC within 24 hours of being recognized. Evidence exists that the report was provided to WECC within 24 hours.

R5 pertains to prompt notification if a report cannot be made to WECC on a timely basis. As this was not the case, this requirement is not applicable to the Event.

R6 obligates the ISO to complete further reporting by WECC if the final report is required. Evidence exists that the AESO did not require any further reporting on the Event.

The AESO was compliant with EOP-004-AB-1.

OPP 401 Regulating Reserve Service

The purpose of OPP 401 *Regulating Reserve Servic*e is to define the policy and procedures for the system controller in dispatching generating units for regulating reserve service to manage regulation range levels in the Alberta control area. The system controller uses the ancillary service merit order, which is sorted in priority sequence and has a maximum contract amount for each offered asset for the dispatching of regulating reserve. Generating units that provide regulating reserve service are controlled by an automatic generation control (AGC) system that adjusts generating unit output levels within an established regulation range to compensate for the moment-to-moment changes in load and generation, as well as to follow the trend in energy imbalances. This compensation provides a balance between generation and load within the Alberta control area.

Prior to the Event, the AESO acquired sufficient regulating reserve resources as required by OPP 401. During the Event, all of the assets were dispatched in priority sequence using the ancillary services merit order. The AESO operated the AGC on Tie Line Bias mode during the shortfall events on this day. Consequently, the AESO was in compliance with OPP 401.

OPP 402 Supplemental and Spinning Reserve Services

The purpose of OPP 402 is to define the contingency reserve criteria for the AIES and provide guidelines and procedures for the system controller in dispatching assets for supplemental and spinning reserve and in issuing ancillary service directives for the delivery of supplemental and spinning reserve energy. As a member of WECC, the AESO is required to carry sufficient operating reserve to assist in the recovery of energy due to the unexpected loss of generation or an interconnection. The criteria for determining minimum operating reserve, contingency reserve and regulating reserve are established by WECC. The AESO may be subject to financial penalties if the criteria in this policy are violated.

Similar to OPP 401, the AESO acquired sufficient supplemental and spinning reserve resources as required by OPP 402 prior to the Event. As described below in Step 12 of Table 1 in OPP 801, at 1:05 p.m., the system controller directed on AESO internal contingency reserve for the first time in an effort to rebalance AIES supply and demand when Keephills 1 tripped off-line. During this time the AIES was vulnerable to increased reliability risks should another generating unit trip have occurred prior to restoring generation reserve. As such, the AESO is permitted to direct these reserves for a maximum of one hour before it must recover its full contingency reserve capacity. As the one hour limit approached, the system controller was attempting to recover operating reserve capacity when Genesee 2 tripped at 2:06 p.m. Those recovered reserves remained directed on for the balance of the EEA. The AESO was compliant with OPP 402.

OPP 404 Ancillary Services Dispatches & Directives

The purpose of OPP 404 is to set out policies for the system controller and market participants. Further, procedures are also set out for the system controller with respect to the exchange of ancillary service dispatch and directive messages and responses.

During the Event, the AESO used ADaMS to issue dispatches and directives to market participants. As mentioned previously, the directives were issued for ancillary services as per ISO Rule 6.3.7. As described in Step 3 of Table 1 in OPP 801, all assets in the merit order were dispatched and Step 19 of the same table describes the directives issued. The AESO was compliant with OPP 404.

OPP 705 Short Term Adequacy Assessments (Equivalent requirements now contained in Section 202.2 Short Term Adequacy and Supply Shortfall)

As noted in the next section, STA assessments were performed as per Step 1 of Table 1 in OPP 801. The AESO was compliant with OPP 705 and the details of the STA assessments are noted below.

OPP 801 Supply Shortfall (Equivalent requirements now contained in Section 202.2 Short Term Adequacy and Supply Shortfall)

The purpose of OPP 801 *Supply Shortfall* was to define the procedures for the system controller to follow in responding to a supply shortfall condition in Alberta in order to maintain AIES reliability. OPP 801 also contained measures to be taken by market participants to assist in alleviating supply shortfall conditions. Table 1 in OPP 801 contained 30 steps which may have been effective in managing supply shortfall conditions to meet the Alberta Reliability Standard regarding control performance.

Step 1 Short Term Adequacy Assessment as per OPP 705 – When the STA program issued an alarm, the system controller was to perform a STA assessment in accordance with OPP 705. For more information on the STA calculation, see the Market Impacts section of this report. On July 9, 2012, the STA assessment indicated sufficient adequacy up until the Keephills 1 unit tripped at 1:06 p.m., approximately one hour before the load shed at 2:10 p.m.

Step 2 Planning Steps – Step 2 required the system controller to perform the planning steps within Section 5.1 of OPP 801 if a supply shortfall is anticipated. A supply shortfall was not anticipated therefore planning steps were not performed.

Step 3 Ancillary Services Assets Dispatched – Step 3 necessitated the use of all the resources in the merit order to maintain the balance between supply and demand and dispatch assets offered into the ancillary service merit order to provide the required amount of operating reserve. In addition, Dispatch Down Service (DDS) with respect to directed long lead time energy was to be dispatched. Long lead time energy is any capacity which takes more than one hour to provide; therefore in a supply shortfall event, directives may be issued for long lead time energy to be provided if the energy can be provided before the supply shortfall is forecasted to end. On July 9, 2012, at 1:07 p.m. all assets in merit order were dispatched. There was no long lead time energy available to be directed, and therefore no associated DDS to dispatch.

Step 4 When EMMO Fully Utilized Notify Ops On-call and Issue Message in ADaMS – In accordance with Step 4, the appropriate AESO personnel were notified at 1:07 p.m. However, due to time constraints resulting from responding to the Keephills 1 trip and the subsequent preparation for the next possible contingency, the message was not sent via the ADaMS or entered in the Shift Log. At 6:58 p.m. AESO operation-on-call were notified that the supply shortfall event had ended.

Step 5 Maximize Import ATC and Notify BCTC[6] – The ATC was at maximum allowed by OPP 304 and OPP 312 through the Event. Since ATC was already maximized given system conditions, BC Hydro did not require notification as the limit did not change.

Step 6 Reduce Export ATC to Zero – Export ATC was already constrained to 0 MW due to AIES demand. As a result the export ATC did not need to be reduced to zero as required by Step 6. Export ATC was re-confirmed at 1:15 p.m. Export TTC remained at 0 MW until 6:46 p.m. when it was returned to normal levels.

Step 7 Curtail One hour DOS – Step 7 required the system controller to curtail one hour DOS. This step was not applicable during the Event as there were 0 MW available to curtail.

Step 8 Curtail Seven Minute DOS – During Step 8, the system controller was to curtail seven minute DOS. At 1:21 p.m. a market participant was currently taking 0 MW DOS 7 and was directed to maintain interruptible load usage to 0 MW. This directive remained in effect until 6:46 p.m., when the market participant was informed they might return to normal DOS usage.

Step 9 Curtail Standard DOS – Step 9 was not applicable during the Event as there were 0 MW available to curtail for standard DOS.

Step 10 Cancel Transmission Maintenance – In compliance with Step 10, at 1:15 p.m. the system controller directed the cancellation of a transmission outage which caused Beddington area generation constraints. The line was restored at 2:03 p.m. Additionally, at 2:04 p.m. the system controller requested a line in the B.C. system to be restored. This line was returned to service at 3:46 p.m. which had the impact of increasing import ATC on the B.C. intertie. The ATC of the interconnection increased from 495 MW to 575 MW.

At 6:50 p.m. BC Hydro was informed that the planned outage concerning the line mentioned above could be performed the next day.

Step 11 Dispatch Unutilized External Reserves – Step 11 required the system controller to utilize any non-dispatched external reserve on the B.C. interconnection. This step was not applicable during the Event as no external reserves were dispatched.

Step 12 Issue Directives for Excess Contingency Reserves – Although it was determined that Step 12 was not applicable during the supply shortfall event, it is important to note that approximately 200 MW of supplemental reserve were directed on to respond to the Keephills 1 unit trip at 1:06 p.m. and were left directed on when the AESO entered the EEA1 as of 1:37 p.m. At 6:46 p.m. all directives were cancelled.

[6] *The BC Transmission Corporation no longer exists and the AESO provides these notifications to BC Hydro.*

Step 13 Dispatch On Standby and Backup Supplemental Load – This step stated that if the duration of the supply shortfall is expected to be less than one hour, then the system controller was to dispatch up supplemental loads with standby supply that is offered in the ancillary service merit order and repeat Step 12 if dispatches are made. There were no additional loads offered for dispatch in the ancillary service merit order during the Event; therefore, Step 13 was not applicable.

Step 14 (a) LLTE – Step 14 (a) was deemed not applicable as there was no long lead time energy previously directed on.

Step 14 (b and c) Request and Issue EEA1 – EEA1 was declared by WECC Reliability Coordinator at 1:37 p.m. Between 1:34 p.m. and 1:38 p.m. all TFOs and DFOs but one were notified by phone as per OPP 802. The Medicine Hat Electric Control Center was not notified as it was not involved in load shedding and therefore did not impact the Event. The system controller's discretion was used in making the determination not to notify the Medicine Hat Electric Control Center.

Step 14 (d) AESO Ops On-call notify Stakeholder Relations and Communication – In accordance with Step 14 (d), AESO operations notified Stakeholder Relations and Communication. At 2:01 p.m. there were internal email communications from AESO operations to the CEO, the Vice President of Operations, the AESO's Corporate Communication department and the Director of Market Operations.

WECC RC declared the AESO in an EEAO at 6:48 p.m. and the required notifications were made.

Step 15 – Step 15 referred to contracts for Import Load Remedial Action Schemes that are no longer in effect; therefore Step 15 was no longer applicable on July 9, 2012 and was removed when content from OPP 801 was transitioned into the new ISO Rules framework as Section 202.2 of the ISO Rules.

Step 16 Ops On-call Consider Public Appeal – As per Step 16, a public appeal was considered as per Step 5 of Section 5.1 of OPP 801. AESO operations worked with Corporate Communication throughout the Event regarding public communications. At 3:39 p.m. Corporate Communication received direction to release the public appeal, and it was issued at 3:51 p.m., requesting a voluntary reduction of electricity use until 6:00 p.m.

Step 17 Three Per Cent Voltage Reduction – The City of Red Deer was requested to reduce their voltage by three per cent. It was determined that voltage reduction for the City of Lethbridge would not have been effective in managing the supply shortfall so the request for voltage reduction was not made. At 6:00 p.m. the City of Red Deer was notified that the voltage reduction was no longer required.

Step 18 MAM Energy Released – Maximum Authorized MW (MAM) is a level of generation for a generating unit which level is higher than maximum capability of the generating unit which can be produced at the expense of voltage levels. This additional generation may be effective in alleviating supply shortfall in the short-term, but generating above MAM levels reduces overall generation capability once the generating unit has operating above MAM for a given period of time. Due to lightning in the 1201L corridor at the time of the EEA1, Step 18 was considered but not performed. As the loss of the B.C. intertie would have had unknown effects on generating units operating above MAM, the system controller made an assessment that system conditions did not permit the use of MAM energy.

Step 19 Direct Internal Ancillary Services for Supplemental and Excess Spinning Reserves – Step 19 required the system controller to issue ancillary service directives for supplemental and excess spinning reserve, except for external reserve. Approximately 200 MW of supplemental reserve which were directed to respond to the Keephills 1 trip at 1:06 p.m. were left directed when the AESO entered EEA1 at 1:37 p.m. DFOs were informed of possible levels of load shed if required between 1:34 p.m. and 2:02 p.m.

From 5:41 p.m. to 6:46 p.m. the supply demand balance allowed ancillary service directives for supplemental reserve to be cancelled.

Step 20 – Content of Step 20 referred to contracts for Import Load Remedial Action Schemes that are no longer in effect; therefore Step 20 was no longer applicable on July 9, 2012 and was removed when content from OPP 801 was transitioned into the new ISO Rules framework as Section 202.2 of the ISO Rules.

Step 21 Permit Mid-Hour Scheduling of Interruptible Energy – If import ATC was available, Step 21 permitted mid-hour interchange transactions with interruptible energy and/or interruptible transmission service from importer on the B.C. intertie and Saskatchewan intertie up to the posted import ATC limit. During the supply shortfall this step was not applicable as the ATC on the B.C. intertie was fully scheduled and SaskPower was experiencing a similar high load situation to the AIES.

Step 22 Reduce Station Service Loads – The request to reduce non-essential station service loads was considered but not performed due to time constraints for the system controller in managing the AIES through the trips of the Genesee 2, Mahkeses 1 and Joffre.

Step 23 Dispatch Voluntary Curtailment Program – Similar to Step 22, the step to curtail voluntary load curtailment program loads in confidential Table 5 was considered but not performed due to time constraints for the system controller in managing the AIES through the trips of the Genesee 2, Mahkeses 1 and Joffre. Through previous experience, the AESO has found that when price is very high (as it was during the Event), only negligible amounts of load remain in the voluntary load curtailment program.

Step 24 Lift ATC Constraints – Step 24 to lift ATC constraints was assessed but not performed. The 1201L was at a heightened risk of trip due to lightning in the 1201L corridor. Operational assessment was that the benefit of restoring curtailed load through increased import was not sufficient to counter the effects on the AIES of a trip on 1201L line at flows corresponding to the increased ATC level, especially since the system controller expected Sundance 3 to return to service shortly.

Step 25 – Content of Step 25 referred to contracts that are no longer in effect, therefore Step 25 was no longer applicable on July 9, 2012 and was removed when content from OPP 801 was transitioned into the new ISO Rules framework as Section 202.2 of the ISO Rules.

Step 26 Dispatch On External Reserves – Step 26 required the system controller to dispatch on external supplemental and external spinning reserve with standby supply types that are offered into the ancillary service merit order, to an amount no greater than the difference between the net interchange schedule on the B.C. intertie and the posted ATC import limit. During the Event, ATC was fully utilized given system conditions and this step was not applicable.

Step 27 Direct External Supplemental and Spinning Reserves – As noted above in Step 26, no external reserve was dispatched on and this step was not applicable.

Step 28 Issue Ancillary Service Directives for Spinning Reserves and Request EEA2 – Due to the loss of Genesee 2 the AIES went immediately from EEA1 to EEA3. As a result EEA2 was not requested or issued by WECC as per Step 28. At 5:41 p.m. the AIES entered EEA1.

Step 29 Request Emergency Energy from BCTC and SaskPower – In compliance with Step 29, emergency energy was requested from Saskatchewan. At 2:24 p.m. 60 MW of emergency energy from Saskatchewan was received. This amount was increased to 100 MW at 3:00 p.m.

In April of 2012, the emergency contract with BCTC terminated. This agreement was replaced with a change to the NWPP agreement by which reserve could be called on in the event of an EEA2 or EEA3. At 2:18 p.m. the system controller requested 50 MW of reserve from the NWPP after Genesee 2 tripped. There was an additional 80 MW requested at 3:50 p.m. when Joffre tripped offline.

The emergency energy from Saskatchewan was terminated at 5:12 p.m. Since NWPP reserve is available for a maximum of one hour, the request for 50 MW of reserve from the NWPP was terminated at 3:16 p.m. and the second request for 80 MW of reserve from the NWPP was terminated at 4:11 p.m. This reserve was terminated slightly after BC Hydro returned 2L113 to service at 3:46 p.m. which increased the ATC available for market scheduling on the B.C. intertie.

Step 30 Issue Firm Load Directives – EEA 3 was declared by the WECC Reliability Coordinator at 2:10 p.m. At approximately 2:10 p.m., 201 MW of load was curtailed, following the procedures in OPP 802. 100 MW of the curtailed load was restored at 2:13 p.m. Cancellation of the remaining load directives was communicated to all parties by 5:14 p.m., at the same time WECC Reliability Coordinator declared EEA2.

In summary, all steps were considered but some were deemed to be not applicable during the Event. One TFO was not notified as required by Step 14 as it was not impacted by the Event. Step 18 was skipped in order to meet the Alberta Reliability Standard regarding control performance. Step 22 and Step 23 were also not performed due to their limited effectiveness and the priority given to managing the AIES through the trip of three major generating units and maintaining system reliability through the trips. Additionally, as described in Step 28, EEA2 was not requested or issued by WECC due to the loss of a large generating unit, whereby the AIES went immediately from EEA1 to EEA3. OPP 801 allowed the system controller to skip one or more steps in Table 1 of OPP 801 when managing a supply shortfall in order to meet the Alberta Reliability Standard regarding control and performance; however, the system controller was to return to skipped steps, if time and operating conditions permit. During the Event, time and operating conditions did not permit the system controller to return to skipped steps. Therefore, the AESO was in compliance with OPP 801.

OPP 802 Energy Emergency Alerts and Firm Load Directives (Equivalent requirements now contained in Section 305.1 Energy Emergency Alerts)

The purpose of OPP 802 was to define the policies and procedures to issue energy emergency alerts and load directives, and to provide guidelines and responsibilities for all parties when receiving energy emergency alerts or load directives from the system controller are received.

OPP 802 was referred to within OPP 801. Instructions for issuing energy emergency alerts and load directives were provided within OPP 802 and the calculation for involuntary load curtailment was found in ISO Rule 6.8. This calculation determined each wire owner’s share of the pro-rata involuntary load curtailment.

As required by Step 14 and Step 30 listed in the above section on OPP 801, the system controller issued an EEA1 and EEA3 by following the procedures listed in Section 5.1 of OPP 802 and made the required notifications with the exception of the Medicine Hat Electric Control Center. The Medicine Hat Electric Control Center was not notified by phone, only email, as it was not involved in load shedding and therefore did not impact the Event. However, OPP 802 did not allow the system controller the same discretion as OPP 801 to skip steps in order to meet the Alberta Reliability Standard regarding control and performance. As noted above, the system controller did not issue an EEA2 as the AIES went immediately from EEA1 to EEA3 due to the loss of the Genesee 2 generating unit.

Finally OPP 802 stated that the system controller was responsible for updating the WECC Reliability Coordinator of the situation until both EEA2 and EEA3 are terminated. The WECC Reliability Coordinator was contacted multiple times throughout the Event up to and including the declaration of EEA0.

The AESO was not entirely in compliance with OPP 802 as one TFO (the City of Medicine Hat) listed in Table 1 was not notified for the energy emergency alerts.

OPP 1304: System Event Monitoring and Disturbance Reporting and OPP 1305: WECC Reliability Management and Related Reporting

The purpose of OPP 1304 is to establish processes for reporting AIES system disturbances and documenting potential recommendations for subsequent action. This OPP outlines criteria for determining relevant AIES events, responsibilities, general content of an Alberta disturbance report, and the identification, tracking and resolution of AIES disturbance issues.

On July 11, 2012 a preliminary disturbance report was created and submitted to NERC and WECC as detailed in EOP-004-AB-1 and OPP 1305. No further information was requested by WECC. A reportable disturbance verification form and a final disturbance report was submitted to the North West Power Pool as per OPP 1305. The AESO was compliant with the requirements of OPP 1304.

Appendix 2:
Authoritative Documents

This appendix contains copies of all the authoritative documents listed in the table on pages 33 and 34.

ISO Rules
Part 300 System Reliability and Operations
Division 301 General
Section 301.2 ISO Directives

Applicability

1 Section 301.2 applies to:

(a) a **market participant**; and

(b) the **ISO**.

Requirements

Directives the ISO Issues

2(1) The **ISO** may issue a **directive** to a **market participant**, including a **directive** to:

(a) increase or decrease the **real power** or **reactive power** output, or both of them, from a facility;

(b) shut down or start up a facility; and

(c) switch **transmission system** elements, alter planned **outage** or maintenance schedules, or load shed.

(2) The **ISO** may issue a **directive** verbally, electronically or in writing.

Requirement to Comply

3(1) A **market participant** must comply with a **directive** it receives subject to any other **ISO rule** or **reliability standard** and the exceptions in subsections 3(2) and 3(3).

(2) A **market participant** that is a **legal owner** of a **generating unit** or an **aggregated generating facility**, or an **operator** of a **generating unit** or an **aggregated generating facility**, must comply with a **directive** it receives subject to the following exceptions:

(a) it considers that a real and substantial risk of damage to its **generating unit** or **aggregated generating facility** could result if it complied with the **directive**;

(b) it considers that a real and substantial risk to the safety of its employees or the public could result if it complied with the **directive**; or

(c) it considers that a real and substantial risk of undue injury to the environment could result if it complied with the **directive**.

(3) A **market participant** that is a **legal owner** of a **transmission facility** or an **operator** of a **transmission facility** must comply with a **directive** it receives, subject to subsection 39(4) of the **Act**.

(4) A **market participant** that is a **pool participant** must, if the instructions contained in a **directive** it receives require an **operator** to take action, immediately communicate the **directive** to the **operator**.

Report Inability to Comply or Communicate

4(1) If a **market participant** is unable to comply with a **directive** or is unable to communicate it to the **operator**, as applicable, then it must, unless otherwise stipulated in the **directive**, verbally notify the **ISO** of the inability and provide reasons.

(2) The **market participant** must provide notice as soon as practical but, unless otherwise stipulated in the **directive**, not later then five (5) minutes after determining it is unable to comply with a **directive** or is unable to communicate a **directive** to the **operator**, as applicable.

Revision History

Effective	Description
2012/07/10	Initial Release

6.3.7 Supply Shortfall Directive

If during the **trading day** the **system controller** determines that the forecasted **AIES load** requirement exceeds the available supply in any **settlement interval,** the **system controller** will use **ISO** supply shortfall operating policies and procedures to issue **directives** as required.

In effect: July 9, 2012

6.8 Involuntary Load Curtailment

Wire owners will curtail demand when directed by the system controller.

During **AIES** conditions when **system load** and **regulating reserve** cannot be met through **dispatches** within **bid** and **offer** constraints, the **system controller** may direct involuntary curtailment of demand by some or all **wire owners**. **Wire owners** will share the involuntary curtailment of demand based on the following:

$$\textit{Wire Owner Load Curtailment} = \textit{Total Load Curtailment Required} \times \frac{\textit{Wire Owner Demand}}{\textit{Total Demand of all Pool Purchasers}}$$

A **wire services provider** may be authorized by a **wire owner** to act on behalf of that owner.

Wire owners' load curtailment plans for supply shortfall events, at minimum, must consider the following factors:

a) The requirements **of LCP**;

b) Operating limit violations;

c) The need to maintain the integrity of **remedial action schemes** and the **under frequency load shedding scheme**;

d) Public safety and environmental impact; and

e) **System controller** discretion to adjust curtailments as required to account for unforeseen circumstances.

EOP–002–AB–2 Capacity and Energy Emergencies

1. Purpose

The purpose of this *reliability standard* is to ensure the ISO is prepared for a supply shortfall event.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must exercise its authority to alleviate a supply shortfall event in the *AIES*.

R2 The *ISO* must implement its capacity and energy emergency plan by following *ISO* rules.

R3 The *ISO* must communicate its current and its forecast of future system conditions to the *VRC* and *adjacent balancing authorities* during a supply shortfall event.

R4 The *ISO* must follow plans in *ISO* rules when it anticipates a supply shortfall event may occur. The *ISO* plans must include any one of or combination of the following:

- Issuing directives as necessary, including bringing on all available generation;
- Postponing equipment maintenance;
- Posting interconnection *TTC* to maximum *reliability* based capacity and being prepared to reduce firm *load*.

R5 The *ISO* must, during a supply shortfall event:

- Only use the assistance provided by the *Interconnection's frequency bias* for the time needed to manage the event.
- Not direct generating units in an attempt to return the *Interconnection* frequency to normal beyond that supplied through *frequency bias* action and *interchange schedule* changes.

R6 The *ISO* must comply with the control performance and disturbance control standards during a supply shortfall event. If necessary to do so, the *ISO* must implement remedies including without limitation, any one of or combination of the following:

- Loading all available generating capacity.
- Deploying all available operating reserves.

- Interrupting interruptible *load* and exports.
- Requesting emergency assistance from other *balancing authorities*.
- Requesting, in accordance with *ISO* rules, the *VRC* to declare an Energy Emergency Alert(s); and
- Reducing *load*, through procedures such as public appeals, voltage reductions, and curtailing interruptible *loads.*

R7 The *ISO* must comply with the control performance and disturbance control *reliability* standards during a supply shortfall event. The *ISO* must perform the following if all the remedies listed in requirement R6 have been implemented and the control performance and disturbance control standards are not being met:

R7.1 Issue directives for the manual shedding of firm *load* without delay to return its *ACE* to zero; and

R7.2 Request, in accordance with the *ISO* rules, the *VRC* to declare an Energy Emergency Alert.

R8 The *ISO* must notify the *VRC* and each *adjacent balancing authority* in the *WECC* that a supply shortfall event exists before revising *system operating limits*.

R9 The *ISO* must complete an "Energy Emergency Alert 3 Report" (refer to template in Appendix 1) and submit it to the *VRC* for review within two business *days* of downgrading or termination of an Energy Emergency Alert 3.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 The following must exist:

- An authorization letter signed by an officer of the *ISO* stating that the persons in the position of *system controller* have the authority to carry out actions and exercise the authority in the requirement.
- Job descriptions for *system controllers* identify the responsibilities of the *system controller* to operate to *ISO* rules and *reliability standards*.

MR2 Procedures to manage a supply shortfall event exist in *ISO rules*.

Disturbance reports, operator logs, voice recordings and/or other data exist that demonstrate the *ISO* managed a supply shortfall event in accordance with its procedures.

MR3 *ISO* rules must include the required communications as identified in R3. Operator logs, voice recordings, electronic communications and/or other data exist to show that communications occurred in accordance with *ISO* rules.

MR4 *ISO* rules must include the planning as identified in R3. Operator logs, voice recordings, electronic communications exist to show that procedures in planning for such an event were met.

MR5 Operator logs, voice recordings, electronic communications and/or other data exist to show that the requirement was met.

MR6 *ISO* rules include the remedies identified in the requirement. Operator logs, voice recordings, electronic communications and/or other data exist to show that the requirement was met.

MR7 Operator logs, voice recordings, electronic communications exist to show that requirement was met.

MR8 Operator logs, voice recordings, electronic communications, electronic data or other equivalent evidence exists to show that the *ISO* notified the *VRC* and each *adjacent balancing authority* that a supply shortfall event exists.

MR9 An "Energy Emergency Alert 3 Report" exists for each event where an Energy Emergency Alert 3 was declared.

7. Appendices

Appendix 1 - Energy Emergency Alert 3 Report (see below)

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Effective	Description
2009-10-03	New Issue

Appendix 1 - Energy Emergency Alert 3 Report

A deficient balancing authority or load serving entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the reliability coordinator for review within two business days of the incident.

Requesting balancing authority:

____

Entity experiencing energy deficiency (if different from balancing authority):

____

Date/Time Implemented:

____

Date/Time Released:

____

Declared Deficiency Amount (MW):

____

Total energy supplied by other balancing authority during the Alert 3 period:

____

Conditions that precipitated call for "Energy Deficiency Alert 3":

____
____
____

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

____
____
____

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.

____
____
____

2. All firm and nonfirm purchases were made regardless of cost.

____
____
____

3. All nonfirm sales were recalled within provisions of the sale agreement.

4. Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.

5. Available load reduction programs were exercised (public appeals, voltage reductions, etc.).

6. Operating Reserves being utilized.

Comments:

Reported By:

Organization:

Title:

EOP–003–AB–1 Load Shedding Plans

1. Purpose

The purpose of this *reliability standard* is to ensure plans are in place and plans are implemented to shed *load* when there is insufficient generation or transmission capacity, to mitigate the risk of an uncontrolled failure of the *Interconnection*.

2. Applicability

This *reliability standard* applies to the entities listed below:

- *ISO*
- *TFOs*
- *demand customers*
- *WSPs* who are counterparties to an agreement with the *demand customer* for the provision of *load* shedding services.

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 When the AIES is operating with insufficient generation or transmission capacity and after considering all remedial steps, the *ISO* must issue *directives* to shed *load*.

R1.1 *Demand customers* and *WSPs* must shed *load* or reduce *MW* inflow as directed by the *ISO*.

R1.2 When coordination with the *ISO* is not possible or practicable, and after considering all remedial steps, the *TFO*, when operating with insufficient generation or transmission capacity, must shed *load* rather than risk an uncontrolled failure of components or *cascading* of the *Interconnection*.

R2 The *ISO* must establish plans for automatic *load* shedding for *underfrequency* or under voltage conditions.

R3 The *ISO* must submit *UFLS* plans to *WECC* for coordination of *UFLS* plans among other *interconnected transmission operators* and *balancing authorities*.

R4 The *ISO* must coordinate *UVLS* plans among other *interconnected transmission operators* and *balancing authorities* external to Alberta.

R5 The *ISO* must consider one or more of these factors in designing an automatic *load* shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.

R6 The *ISO* must implement automatic *load* shedding in *MW* blocks established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R7 After the *AIES* separates from the *Interconnection*, if there is insufficient generating capacity to restore frequency following automatic *underfrequency load shedding*, the *ISO* must issue *directives* to shed additional *load*.

R8 The *ISO* must coordinate automatic *load* shedding throughout Alberta with *underfrequency* isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.

R9 The *ISO* must have procedures for directing operator controlled manual *load* shedding to respond to real-time emergencies.

R10 The *ISO* must be capable of directing manual *load* shedding in a time frame adequate for responding to the emergency.

R11 *Demand customers* and *WSPs* must be capable of implementing manual *load* shedding in a time frame adequate for responding to the emergency.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

These measures will be used by the *ISO* in carrying out its *compliance monitor*ing duties in accordance with *ISO rule* 12. The *ISO* may consider other data and information, including any provided by a *market participant*.

MR1 Voice recordings and logs exist to confirm the *ISO* issued *directives* to shed *load*.

MR1.1 Electronic logs, metering or electronic data exists to confirm the *market participant* shed *load*.

MR1.2 Electronic logs and/or electronic data exist to confirm the *TFO* shed *load*.

MR2 Automatic *load* shedding plans exist. Plans meet the defined need of *load* shedding situations.

MR3 Written confirmation from *WECC* that the *ISO* submitted *UFLS* plans.

MR4 Written confirmation from *interconnected transmission operators* and *balancing authorities* external to Alberta indicating that the *ISO* coordinated *UVLS* plans.

MR5 One or more of these factors were considered in the design of the *load* shed scheme.

MR6 One or more *MW* blocks exist in *load* shed plans or schemes.

MR7 Voice recordings and logs exist to confirm the *ISO* issued *directives* to shed additional *load*.

MR8 *ISO rules*, *interconnection* standards or studies exist to show coordination with automatic actions.

MR9 Procedures exist for directing operator controlled manual *load* shedding.

MR10 Electronic logs, and/or voice recordings exist to confirm the *ISO* directed manual *load* shedding. Manual *load* shedding is performed in a time frame adequate to respond to the emergency as defined in operating procedures or equipment ratings.

MR11 Electronic logs, metering or electronic data exists to confirm the manual *load* shedding. Manual *load* shedding is performed in a time frame adequate to respond to the emergency as defined in operating procedures or equipment ratings.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Effective	Description
2009-06-17	New Issue

EOP– 004–AB–1 Disturbance Reporting

1. Purpose

The purpose of this *reliability standard* is to ensure that events that jeopardize the operation of the *bulk electric system* (*BES*), or result in *system* equipment damage or customer interruptions, are studied and understood to minimize the likelihood of similar events in the future. To ensure that disturbances and unusual occurrences are reported to *WECC* and *NERC*.

2. Applicability

This *reliability standard* applies to the entities listed below:

- *ISO*
- *TFOs*
- *GFOs*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must promptly review events as described in Appendix 1 to determine if a *NERC* "Interconnection Reliability Operating Limit and Preliminary Disturbance Report" needs to be completed**.**

R2 The *ISO* must analyze events on the *AIES* in accordance with *OPP* 1304.

R3 *TFOs* and *GFOs* must analyze disturbances on its *system* or *facilities* as requested by the *ISO* in accordance with *OPP* 1304.

R4 If a reportable event occurs, the *ISO* must provide a *NERC* "Interconnection Reliability Operating Limit and Preliminary Disturbance Report", as included in Appendix 1, to *WECC* and *NERC* within 24 hours of being recognized.

R5 Under certain conditions, such as severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written "Interconnection Reliability Operating Limit and Preliminary Disturbance Report" within 24 hours. In such cases, the *ISO* must promptly notify the *Vancouver Reliability Coordinator (VRC)*, and verbally provide as much information as is available at that time. If the *ISO* makes such notification, the *ISO* must then provide timely, periodic verbal updates until adequate information is available to issue a written "Interconnection Reliability Operating Limit and Preliminary Disturbance Report".

R6 If, in *WECC's* judgment, after consultation with the *ISO*, a final report is required, the *ISO* must prepare this report in accordance with "WECC Reporting Procedures for System Events".

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

These measures will be used by the *ISO* in carrying out its *compliance monitor*ing duties in accordance with *ISO rule* 12. The *ISO* may consider other data and information, including any provided by a *market participant*.

MR1 Preliminary disturbance reports exist for events as described in Appendix 1.

MR2 An *AIES* Disturbance Report exists for each event selected for further assessment in accordance with *OPP* 1304.

MR3 Information provided meets the requirements of the request.

MR4 Written confirmation from *WECC* exists that shows the *ISO* provided preliminary disturbance reports to *WECC* within 24 hours of the event being recognized.

MR5 Shift logs, voice recordings or electronic communications exist to confirm that the requirement is met.

MR6 Written confirmation exists that shows the *ISO* provided a final report in accordance with “WECC Reporting Procedures for System Events”.

7. Appendices

Appendix 1

Interconnection Reliability Operating Limit and Preliminary Disturbance Reporting Criteria and Form

The *NERC* "Interconnection Reliability Operating Limit and Preliminary Disturbance Reports" are to be made for any of the following events:

1. The loss of a bulk power transmission component that results in frequency or voltage going below the *underfrequency* or *under voltage load shed* points.
2. The occurrence of an interconnected *system* separation or *system* islanding or both.
3. Loss of 2000 *MW* or more of generation or *load* in Alberta.
4. Equipment failures/system operational actions which result in the loss of 300 *MW* of *demand* for more than 15 minutes.
5. Firm *load* shedding 100 *MW* or more to maintain continuity of the *BES*.
6. Any action taken by a generator operator, *TFO*, *WO*, *WSP*, transmission connected end use customer or *ISO* that results in:
   a) Sustained voltage excursions equal to or greater than ±10%, or
   b) major damage to power *system* components, or
   c) failure, degradation, or misoperation of *system protection*, special protection schemes, *remedial action schemes*, or other operating systems that do not require operator intervention, which did result in, or could have resulted in, a *system* disturbance as defined by Steps 1 through 5 above.
7. An *IROL* violation.

NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

☐ Check here if this is an Interconnection Reliability Operating Limit (IROL) violation report.

1.	Organization filing report.		
2.	Name of person filing report.		
3.	Telephone number.		
4.	Date and time of disturbance. Date:(mm/dd/yy) Time/Zone:		
5.	Did the disturbance originate in your *system*?	☐ Yes ☐ No	
6.	Describe disturbance including: cause, equipment damage, critical services interrupted, *system* separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence.		
7.	Generation tripped. MW Total: List generation tripped:		
8.	Frequency. Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):		
9.	List transmission lines tripped (specify voltage level of each line).		
10.		Firm	Interruptible
	Demand tripped (MW):		
	Number of affected Customers:		
11.	Restoration time.	Initial	Final
	Transmission:		
	Generation:		
	Demand:		

Copies to be sent to:

- WECC at disturbancereports@wecc.biz
- NERC at esisac@nerc.com

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Effective	Description
2009-06-17	New Issue

401 REGULATING RESERVE SERVICE

1. Purpose

To define the policy and procedures for the System Controller (SC) in dispatching generators for regulating reserve service to manage regulation range levels in the Alberta control area.

2. Background

As a member of the Western Electricity Coordinating Council (WECC), the ISO is required to carry sufficient operating reserves. The criteria for determining minimum operating reserves, contingency reserves plus regulating reserves, are established by the WECC. Based on regulating reserve levels identified in Table 1, the ISO will procure regulating reserves from the ancillary service exchange or by other means. The SC may be required to adjust the volume of regulating reserve in real-time based on actual system conditions.

Generators that provide regulating reserve service are controlled by an automatic generation control (AGC) system that adjusts generator output levels within an established regulation range to compensate for the moment-to-moment changes in load and generation, as well as to follow the trend in energy imbalances. This compensation provides a balance between generation and load within the Alberta control area while maintaining the interchange schedule on the interconnection with British Columbia and the scheduled frequency of 60 Hz. AGC performance is monitored through the use of the North American Electric Reliability Council (NERC) control performance standards.

Regulation range is the total amount of generation (MW) made available for AGC operation between the upper and lower regulating limits of each generator providing the regulating reserve service.

All generators on AGC are controlled through either the AltaLink AGC master controller or the ISO AGC master controller. When operating in the set point control mode, all generators will respond to control set points calculated by the ISO AGC master controller. The set point specifies for each generator a MW control level to ramp to, based on their portion of the total AGC range being used in the AIES at the time.

The SC uses the ancillary service merit order, which is sorted in priority sequence and has a maximum contract amount for each offered asset, for the dispatching of regulating reserve. The ancillary service merit order contains three supply types: active, standby and backstop. Regulating reserve assets with an active supply type will normally be dispatched and assets with a standby or backstop supply type will only be dispatched if required.

3. Policy

3.1 General

- Operating reserves consist of regulating reserves and contingency reserves. This document addresses regulating reserves and OPP 402 addresses contingency reserves.
- The volume (MW) of regulation range will not be less than the minimum shown in Table 1.

- The maximum amount of energy that will be dispatched for each asset is equal to the ISO contract amounts displayed in the ancillary service merit order or the amount the ancillary service provider has made available in the energy trading system ancillary service declarations, whichever is less.
- The marginal asset dispatched for regulating reserve service can be partially dispatched.
- In the set point control mode, the ISO AGC master controller calculates the set points for all generators providing regulating reserves. The set point calculation considers the high regulating limit, low regulating limit and ramp rate as per operating constraints for each generating unit.
- All regulating reserve service assets controlled by the AltaLink AGC master controller will normally be operated in the EX (external base point) control mode with a priority set at 0, which will use the set points calculated by the ISO AGC master controller.
- Regulating reserve service assets controlled directly by the ISO AGC master controller are either on or off and have no other specific control modes.
- Resources may be suspended if they do not comply with the applicable Technical Requirements. Suspended resources will not be included in the ancillary service merit orders unless they have been reinstated.

3.2 Priority for selecting portfolios

- Resources from the active portfolio are to be fully dispatched unless such dispatch would jeopardize system reliability. If there is a risk to system reliability, reduced volumes of active resources may be dispatched.
- If active portfolio resources are insufficient to meet the system requirements for regulating reserves then ancillary service resources from the standby portfolio will be dispatched.
- Standby portfolio resources will be dispatched from the ancillary service merit order. The ancillary service merit order sets out the priority order of the dispatch. Standby portfolio resources will be dispatched in order of increasing priority with the lowest priority being dispatched first.
- Resources from the backstop portfolio will be dispatched when the resources in the active and standby portfolios are insufficient to meet the system requirements.
- The ancillary service resources of the backstop portfolio will be dispatched from the ancillary service merit order. The ancillary service merit order contains an indicator for the priority of the dispatch. Resources in the backstop portfolio will be dispatched in order of increasing priority and the backstop resource with the lowest priority will be dispatched first.
- Under circumstances when more regulating reserves are required than are offered/dispatched in all portfolios (active, standby and backstop), then directive(s) will be issued to direct those ancillary services resources that are not offered in the ancillary services market to provide ancillary services.

3.3 Regulating reserve dispatches under system constraints

- System constraints can cause regulating reserve dispatch to be either:
  - A partial dispatch from lower priority ancillary services; or
  - A bypass of the dispatch of a lower priority resource.
- System constraints can result from either:
  - System conditions where the dispatch of resources from the active portfolio would jeopardize system reliability; or
  - Transmission outage events restricting the flow of energy from an area, thereby limiting the utilization of some resources.

3.4 AGC

- The ISO will operate the AGC on Tie Line Bias (TLB) mode unless such operation is adverse to system or interconnection reliability.
- When the AIES is separated from the Western Interconnection, the AGC will be operated on Constant Frequency (CF) mode.
- If the ISO is unable to calculate area control error (ACE) for more than 30 minutes, the Vancouver Reliability Coordinator (VRC) will be notified

4. Responsibilities

4.1 ISO

The ISO will:

- As required, review and revise the requirements for regulation range and regulating reserves.
- Acquire sufficient regulating reserve resources for the active, standby and backstop portfolios.
- Monitor and assess the performance of resources providing regulating reserve service.

System Controller (SC)

The SC will:

- Dispatch assets for regulating reserve service according to the ancillary services merit order, starting with the lowest numbered regulating reserve service offer in the priority sequence.
- Ensure a dispatch time of no less than 15 minutes from the time of dispatch, unless mutually agreed to with the ancillary service provider.
- Ensure active supply type assets are fully dispatched whenever possible.
- Identify assets providing the regulating reserve service with an RR service type using the dispatch tool.

- When practical, maintain a regulation range, on an hourly average, between the minimum range and maximum range shown in Table 1.
- If the maximum range indicated in Table 1 is exceeded because the SC needs more regulation range due to system conditions, log the reason in the dispatch tool comment field of the asset(s) dispatched above the maximum range.
- Operate the AGC on TLB mode unless such operation is adverse to system or interconnection reliability.
- Operate the AGC on CF mode when the AIES is separated from the Western Interconnection.
- Notify the VRC if Alberta has lost the capability to calculate ACE or to operate the AGC for more than 30 minutes.

4.2 Ancillary Service Provider

The ancillary service provider will:

- Restate the ancillary service declarations 30 minutes before the start of the hour, if possible. This will ensure restated active supply type assets will be dispatched. By 15 minutes before the start of the hour, the SC will have ancillary services dispatched. Ancillary service providers restating ancillary service declarations after this time need to call the SC to inform him of the change in their ancillary service declarations. The SC will then assess at what time the changed asset can be dispatched.
- Ensure that the appropriate ramp rate for the generating unit providing the regulating reserve service is entered in the operating constraints. This ramp rate will be used in the set point calculation by the ISO AGC master controller and must match that of the unit capability.
- Position the generator within the established regulation range and have the generator(s) ready to respond to control signals from the AGC controller by the dispatch time.
- Decline a dispatch received with less than 15 minutes to the dispatch time if they are unable to comply. The ancillary service provider will then immediately call the SC to explain the reason for declining the dispatch, at which time the SC will assess if another asset will be dispatched or if the asset will be re-dispatched with no less than 15 minutes to the dispatch time.
- Notify the SC of any changes to the regulation range of a generator providing regulating reserve service and restate the asset's ancillary service offer to reflect this change.
- Restate the availability of the generator if the asset is withdrawn from actively providing regulating reserve service.
- Restate out of the energy market merit order any energy issued an ancillary service dispatch from the ancillary services merit order. A restatement must be submitted any time energy availability or amounts change.
- Comply with SC directives to direct ancillary services resources that are not in the ancillary services market to provide ancillary services, unless there is an immediate risk to personnel, equipment safety, environment (including hydrological constraints) or the public.

4.3 TransAlta Generation Operator

The TransAlta Generation Operator will:

- As directed by the SC, include in or remove from the AltaLink AGC master controller, regulating reserve assets.
- Ensure regulating reserve assets included in the AltaLink AGC master controller are in EX - external base point mode with a priority set at 0 unless notified by the SC to change to the CE mode.

5. System Controller Procedures

5.1 Dispatching assets on regulating reserve service

The SC will:

1. Dispatch up all regulating reserve assets with an active supply type offered in the ancillary service merit order, unless an asset can cause a risk to system reliability, and identify to the ancillary service provider the:
   a. Dispatch time, which will be no less than 15 minutes from the time of dispatch unless mutually agreed to with the ancillary service provider.
   b. Amount (MW) of regulating reserve service required.
2. Determine the amount of regulation range needed to meet the real time operational requirements of the AIES.
3. Refer to Table 1 to identify the minimum regulation range and maximum regulation range for the hour.
4. If more regulating reserve service is required than is offered as active supply type, select the regulating reserve asset(s) and volume of regulation range to dispatch according to their priority in the ancillary services merit order in the dispatch tool.
5. When a regulating reserve asset with a standby or backstop supply type is dispatched, identify one of the following causes in the dispatch tool comments:
   a. Insufficient resources to meet requirements.
   b. Failure of another resource.
   c. Declined dispatch by another resource.
   d. Transmission constraint.
6. Dispatch the regulating reserve asset using the ancillary service merit order in the dispatch tool and identify:
   a. The time the asset is to provide the regulating reserve service. This time is to be no less than 15 minutes after the ancillary service dispatch is issued to the provider unless mutually agreed to by the SC and the ancillary service provider.
   b. Amount (MW) of regulation range required.

7. If more regulating reserves are required than are offered/dispatched in all portfolios:
   a. Direct regulating reserve resources that are not offered in the ancillary services market to provide ancillary services with use of the ancillary service dispatch tool. The tool will flag these regulating reserve resources as "O" (out of market).
   b. Follow up the directive with a phone call to the regulating service provider to confirm.
   c. Adjust the directive volume if required as system conditions change.
   d. Cancel the directive when it is not required.
   e. Enter in the shift log the details of the directive including reasons, times and participant names, as described in OPP 1301.
8. Check Ranger display 6955, AGC, to confirm the AGC parameters for each generator.
9. If the AltaLink AGC master controller controls the regulating reserve asset and AGC is operating:
   a. in the set point control mode refer to Section 5.3.
   b. in the percentage of ACE control mode, refer to Section 5.7.
   c. with AltaLink performing the master controller function, refer to Section 5.5.
10. Refer to Section 5.4 if the ISO AGC master controller controls the regulating reserve asset.

5.2 Dispatching assets off regulating reserve service

The SC will:

1. Determine the amount of regulation range no longer required.
2. Dispatch off the regulating reserve asset in descending priority as indicated in the ancillary service merit order in the dispatch tool.
3. Enter the date and time the regulating reserve asset was dispatched off in the dispatch tool.
4. Refer to Section 5.3 step 2 if the AltaLink AGC master controller controls the regulating reserve asset.
5. Refer to Section 5.4 step 3 if the ISO AGC master controller controls the regulating reserve asset.

5.3 Regulating reserve assets controlled by the AltaLink AGC master controller

For each regulating reserve asset controlled by the AltaLink AGC master controller, the SC will request the TransAlta Generation Operator to:

1. Include in the AltaLink AGC master controller each of the dispatched regulating reserve assets controlled by the AltaLink AGC master controller.
2. Ensure when operating in the set point control mode that the AltaLink AGC master controller is set to the EX - external base point mode with a priority set at 0. Refer to Section 5.5 if AltaLink is performing the AGC master controller function or refer to Section 5.7 if the ISO AGC controller is operating in the percentage of ACE control mode.

3. When an asset is dispatched off of regulating reserve service, request the TransAlta Generation Operator to remove the asset from the AltaLink AGC master controller.

5.4 Regulating reserve assets controlled by the ISO AGC master controller

For each dispatched regulating reserve asset controlled through the ISO AGC master controller the SC will:

1. On Ranger display 3913, AGCALL, ensure the following:
    a. The Auto Part % poke point is solid blue. This is the preferred condition as it indicates the participation factor is being calculated automatically. If the poke point is an open white square the SC must calculate the participation factor for each asset by using the formula:

    $$\% \text{ Participation factor of asset} = \frac{\text{Regulation range of asset}}{\text{Total dispatched regulation range}} \times 100\%$$

    b. The NAME column displays the asset name. Squares in this column will indicate red if the individual generators at the plant are on AGC and the squares will be open when the generator is off AGC.
    c. The DT column indicates by the green diamond that the asset has been dispatched on through the dispatch tool.
    d. The AGC column indicates On. A red On indicates the plant has turned on their AGC, the asset has been dispatched on through the dispatch tool and Set PT Control and ACE Control on Ranger display 1275, PLTREGMO are on. The 1275 indications normally do not require adjustment.
    e. Ensure the raise and lower ranges are accurately reflected in the Control Range columns.
    f. Ensure the plant is reacting properly to the value shown in the SIGNAL column. This value is the control signal being sent to the plant and the plant should be ramping to this level. The signal for AltaLink indicates their portion of ACE and not an actual target value.
    g. Ensure the participation factor, shown in the ACE Part Fact column, is correct for each dispatched asset.
    h. Ensure the value shown in the ACTUAL column reflects the actual output of the plant on AGC. If the plant is on AGC this value should be dynamic and moving towards the value shown in the SIGNAL column.
2. Access Ranger display 1275 if problems are encountered with the plant's AGC parameters by clicking the MO poke point on Ranger display 3913. The SC has the ability to change the status, the level, the range and the ramp rates of the plants on AGC by implementing an override on this display. If the plant has tripped off of AGC due to tracking or other software issues, the Setpnt Output Mode will have to be turned back on from this display.
3. To remove the plant from AGC service, dispatch the asset off of regulating reserve service using the dispatch tool.
4. If a generator cannot be put on AGC through the dispatch tool and an override is required, go to display 3913, click the point in the MO column for the appropriate generator. This action will cause a jump to display 1275, from this display change the

status of the generator in the override column to on. The AGC status on display 3913 will change to on.

5.5 Switching the AGC master controller function from the ISO to AltaLink

If the ISO AGC master controller fails and the AGC master controller function needs to be switched to AltaLink, the SC will:

1. From display 3913 or 1120 switch the ISO AGC master controller to the monitor mode by clicking the "AGC Monitor" soft key.
2. Request the TransAlta Generation operator to:
   - Switch the AGC control mode for all generators on AGC from the EX - external base point mode to the CE mode.
   - Assign a priority of 1 to all generators on AGC.
   - Manually select the appropriate heat rate curve for the range that each hydro generator is being regulated in.
3. Request the AltaLink South Transmission operator to switch their AGC master controller to deactivate the use of the external ACE signal received from the ISO.
4. Ensure the AltaLink South operator has the correct schedule in place for the BC interconnection.
5. As required to assist regulation, manually dispatch generators that are no longer directly receiving set points from the ISO AGC master controller by overwriting the set points for each generator on display 3913.
6. Refer to Section 5.6 to return to normal operation.

5.6 Return to normal operation – Switching the AGC master controller function from AltaLink to the ISO

To return to normal operation the SC will:

1. Request the TransAlta Generation operator to switch the AGC control mode for all generators on AGC from the CE mode to the EX - external base point mode and to assign a priority of 0 to all generators on AGC.
2. Go to display 3913 or 1120 and turn on the ISO AGC master controller by clicking the "Restart AGC" soft key.
3. Perform the following to verify participant control for AltaLink is off:
   - Go to display 1246 and find "TAU" under "PARTICIPANT NAME" (try page 5).
   - Check the corresponding "ACE OUTPUT MODE" field is "OFF". If this field indicates "ON" then turn it off.
4. Request the AltaLink South Transmission operator to activate the use of the external ACE from the ISO on their AGC master controller and notify the operator that the ISO AGC controller is operating in external set point control.
5. If generators were manually dispatched for regulation by the SC, go to display 3913 and remove the override from the generator set points.

5.7 Switching AGC to Percentage of ACE control mode

If there is a problem operating in the set point control mode with AltaLink, and the ISO AGC master controller can be switched to the percentage of ACE control mode, the SC will:

1. Request the TransAlta Generation operator to:
   - Switch the AGC control mode for all generators on AGC from the EX - external base point mode to the CE mode.
   - Assign a priority of 1 to all generators on AGC.
   - Manually select the appropriate heat rate curve for the range that each hydro generator is being regulated in.
2. Perform the following to turn participant control for AltaLink on:
   - Go to display 1246 and find “TAU” under “PARTICIPANT NAME” (try page 5).
   - Turn the corresponding “ACE OUTPUT MODE” field to “ON” (the ISO AGC master controller will now send a percentage of ACE to the AltaLink AGC master controller).
3. Call the AltaLink South Transmission operator and:
   - Verify their AGC master controller has external ACE set to active.
   - Notify the operator that AltaLink should now be receiving a portion of the ACE signal from the ISO AGC master controller.
   - Request to be notified if there are any problems. Confirm the dynamic BC interchange schedule is being received.
4. To return to normal operation refer to Section 5.8.

5.8 Return to normal operation – Switching AGC from Percentage of ACE control mode to set point control mode.

To return to normal operation the SC will:

1. Request the TransAlta Generation operator to switch the AGC control mode for all generators on AGC from the CE mode to the EX - external base point mode and to assign a priority of 0 to all generators on AGC.
2. Perform the following to turn participant control for AltaLink off:
   - Go to display 1246 and find “TAU” under “PARTICIPANT NAME” (try page 5).
   - Turn the corresponding “ACE OUTPUT MODE” field to “OFF” (the ISO AGC master controller will now send a percentage of ACE to the AltaLink AGC master controller).
3. Verify with the AltaLink South Transmission operator that their AGC master controller has external ACE set to active. Notify the operator that the ISO AGC master controller is operating in the external set point control mode.

5.9 Notifying the VRC

If the ACE can not be calculated by either the ISO system or the AltaLink system for more than 30 minutes, or the AGC fails on both systems, the SC will:

1. Notify the VRC.
2. Log the event as described in OPP 1301.
3. Notify the VRC and log the event when the ACE calculation and the AGC return to normal function.

6. Figures and Tables

Table 1

Regulation range guidelines

Time Period (Hour Ending)	Minimum Regulation Range (MW)	Maximum Regulation Range (MW)
1	110	175
2	110	175
3	110	175
4	110	175
5	110	175
6	110	225
7	110	225
8	110	225
9	110	225
10	110	175
11	110	175
12	110	175
13	110	175
14	110	175
15	110	175
16	110	175
17	110	225
18	110	225
19	110	225
20	110	225
21	110	225
22	110	225
23	110	225
24	110	225

7. Revision History

Issued	Description
2008-11-13	Supersedes 2007-03-15
2007-03-15	Supersedes 2005-12-01
2005-12-01	Supersedes 2004-05-19
2004-05-19	Supersedes 2004-02-24
2004-02-24	Approved for interim implementation
2003-07-28	Revised to ISO Operating Policies and Procedures

402 SUPPLEMENTAL AND SPINNING RESERVE SERVICES

1. Purpose

To define the contingency reserve criteria for the Alberta Interconnected Electrical System (AIES) and provide guidelines and procedures for the System Controller (SC) in dispatching assets for supplemental and spinning reserves and in issuing an ancillary service directive for the delivery of supplemental and spinning reserve energy.

2. Background

As a member of the Western Electricity Coordinating Council (WECC), the ISO is required to carry sufficient operating reserves to assist in the recovery of energy due to the unexpected loss of generation or an interconnection. The criteria for determining minimum operating reserves, contingency reserves plus regulating reserves, are established by the WECC. The ISO may be subject to financial penalties if the criteria in this policy are violated.

Forecasts of minimum operating reserve levels are required by the ISO in order to procure operating reserves from the ancillary service exchange or by other means. The ISO procures ancillary services in the ancillary services market in three portfolios:

- Active portfolio
- Standby portfolio
- Backstop portfolio

The purpose of the active portfolio is to meet the ancillary services requirements of the AIES under normal operating conditions. Assets in this portfolio will normally be dispatched.

There is a standby portfolio of resources for each of the ancillary service types procured in the ancillary services market. The purpose of the standby portfolio is to provide additional ancillary services resources for use when the resources available under the active portfolio are insufficient. Generally, before any resources will be dispatched from the standby portfolio, all resources have been dispatched from the active portfolio.

There is a backstop portfolio of resources for each of the ancillary service types procured in the ancillary services market. The purpose of the backstop portfolio is to provide additional ancillary services resources for use when the resources available under both the active and standby portfolio are insufficient. Generally, before any resources will be dispatched from the backstop portfolio, all resources will have been dispatched from the active and standby portfolios.

The SC will use the ancillary service merit order, sorted in priority sequence, for the dispatching of supplemental and spinning reserves.

3. Policy

3.1 General

- Operating reserves consist of regulating reserves and contingency reserves. This document provides an overview of operating reserve criteria, with details of contingency reserves requirements. OPP 401 addresses details on regulating reserves.
- Sufficient contingency reserves are required to reduce area control error to zero or to its pre-disturbance level within 15 minutes of a contingency.
- At least 50% of contingency reserves must be spinning reserve.
- The Alberta control area will be operated to meet the Disturbance Control Standard (DCS) as defined by NERC.
- The Alberta control area will be operated using best efforts to recover from any multiple supply contingency within 15 minutes, with all available resources including assistance from neighbouring control areas.
- Import or export energy interchange transactions with the Alberta control area will be firm interchange transactions.
- The following data will be recorded and stored for a period of not less than one year and with sufficient resolution, per NERC guidelines, to permit the assessment of system performance:
  - System ACE (raw and filtered)
  - System frequency
  - Net tie line interchange
  - Available regulating reserve, and raise and lower ranges
  - Available spinning reserve
  - Available supplemental reserve
- The NWPP Reserve Sharing Agreement may be invoked in the event of both single and multiple contingencies.
- Supplemental reserves, spinning reserves or regulating reserve service can provide supplemental reserve requirements.
- Either spinning reserves or regulating reserve service can provide spinning reserve requirements.
- Assets dispatched to provide supplemental or spinning reserve service will receive one of the following service types in the ancillary service merit order:

  SUPG — To identify a generating unit connected to the AIES that is supplying supplemental reserves.

  SUPL — To identify a load connected to the AIES that is supplying supplemental reserves.

  SR — Spinning reserves.

RR Regulating reserve service.

- Any one generator will provide no more than 80 MW of spinning reserve.
- The maximum amount of energy that will be dispatched for each asset is equal to the ISO contract amounts displayed in the ancillary service merit order or the amount the ancillary service provider has made available in the energy trading system (ETS) ancillary service declarations, whichever is less.
- The amount (MW) of an ancillary service directive for spinning or supplemental reserves will be the total volume of demand (MW) required from an individual asset. Ancillary service directives following an initial directive are also for the total volume of demand (MW) required and are to be used instead of, and not added or subtracted from, the volume in the previous directive.
- Each directive issued to ancillary service providers indicates the amount (MW) of the directive and the remaining amount (MW) of reserve in that asset as well as the time the directive was issued.
- For compliance monitoring reasons, the SC will not adjust the dispatch time to a time in the past. Dispatches are to indicate either the present time or a future time.
- Ancillary service directives will take precedence:
  - When ancillary service directives are issued before previously dispatched energy market dispatches can be completed; see Figure 1 and Figure 2.
  - When ancillary service directives are issued at the same time as energy market dispatches. Figure 3 demonstrates the response for an energy dispatch down. For an energy dispatch up, the ancillary service asset is expected to complete the directive ramp up then continue the energy dispatch ramp up.
  - When energy market dispatches are issued before previously issued ancillary service directives can be completed. Figure 3 demonstrates the response for an energy dispatch down. For an energy dispatch up, the ancillary service asset is expected to complete the directive ramp up then continue the energy dispatch ramp up. See Figure 2.
- Once an ancillary service directive is issued, the resumption of an energy market dispatch down is delayed until 15 minutes after the directive time. Fifteen minutes is the maximum time a control area is allowed to recover its area control error after a contingency, so this delay ensures that operating reliability standards are met. The ancillary service provider may call the SC before the 15 minutes has expired to seek approval to proceed with the energy market dispatch down. The SC will assess the system conditions to decide whether or not to allow the energy market dispatch to proceed.
- An ancillary service directive remains in effect for 60 minutes or until cancelled by the SC, whichever is the shorter time period, even if it extends into an hour that the asset is no longer offered or an hour in which the amount offered has changed.
- Contingency reserve will be promptly restored after any occurrence necessitating its use and the time taken to restore will not exceed 60 minutes.

- Resources may be suspended if they do not comply with the applicable Technical Requirements. Suspended resources will not be included in the ancillary service merit orders unless they have been reinstated.

3.2 Contingency reserve requirements

- The contingency reserve requirements depend on the operating states of 1201L and other transmission elements as indicated in Table 1.
- The arming of ILRAS, which impacts the Alberta contingency reserve requirements, is covered in OPP 312.
- Appendix A provides examples of the determination of contingency reserve requirements, for various conditions of import and export, and 500 kV tie line status.

3.3 Priority for selecting portfolios

- Resources from the active portfolio are to be fully dispatched unless such dispatch would jeopardize system reliability. When one or more of the conditions described in Section 3.4 exist, reduced volumes of active resources may be dispatched or dispatches not following the ancillary services merit order may be required
- If active portfolio resources are insufficient to meet the system reserve requirements then ancillary service resources from the standby portfolio will be dispatched.
- Standby portfolio resources will be dispatched from the ancillary service merit order. The ancillary service merit order sets out the priority order of the dispatch. Standby portfolio resources will be dispatched in order of increasing priority (i.e., the lowest priority will be dispatched first). Dispatches not following the ancillary services merit order may be required when one or more of the conditions described in Section 3.4 exist.
- Resources from the backstop portfolio will be dispatched when the resources in the active and standby portfolios are insufficient to meet the system reserve requirements.
- The ancillary service resources of the backstop portfolio will be dispatched from the ancillary service merit order. The ancillary service merit order contains an indicator for the priority of the dispatch. Resources in the backstop portfolio will be dispatched in order of increasing priority and the backstop resource with the lowest priority will be dispatched first. Dispatches not following the ancillary services merit order may be required when one or more of the conditions described in Section 3.4 exist.
- Under circumstances when more supplemental or spinning reserves are required than are offered/dispatched in all portfolios (active, standby and backstop), then directive(s) will be issued to direct those ancillary service resources that are not offered in the ancillary service market to provide ancillary services. The system controller will determine which ancillary service resource to be directed with consideration of factors as described in confidential Appendix B.

3.4 Ancillary service dispatches under system constraints

- System constraints cause ancillary service dispatch to be either:
  - A partial dispatch from lower priority ancillary services; or
  - A bypass of the dispatch of a lower priority resource.

- System constraints can result from either:
  - System conditions where the dispatch of resources from the active portfolio would jeopardize system reliability; or
  - Transmission outage events restricting the flow of energy from an area, thereby blocking the utilization of some resources.

4. Responsibilities

4.1 ISO

The ISO is responsible for:

- Reviewing the management of operating reserve on an ongoing basis to ensure consistency with WECC, NWPP and NERC criteria and ensure that Alberta control area reliability is maintained.
- Procuring adequate levels of operating reserve.
- Producing an ancillary services merit order for dispatch of operating reserve resources.
- The ISO may suspend resources that fail to comply with the applicable Technical Requirements. Anytime a resource is suspended, the ISO will not include that resource in the ancillary service merit order, until that resource is re-instated.

System Controller

The SC is responsible for:

- Ensuring the required amount of contingency reserve is in place at all times by dispatching a combination of spinning, supplemental and regulating reserves from the ancillary service merit order.
- Ensuring active supply type assets are fully dispatched whenever possible.
- Fully or partially dispatching flexible supplemental and spinning reserve assets.
- Fully dispatching non-flexible supplemental and spinning reserve assets and carry additional reserves when the non-flexible asset is on the margin and the full amount is not required.
- Dispatching flexible supplemental and spinning reserve assets for an amount of at least 5 MW.
- Ensuring a dispatch time of no less than 15 minutes from the time of dispatch, unless mutually agreed to with the ancillary service provider.
- Identifying, through use of the dispatch tool, supplemental and spinning reserve assets with an ancillary service directive (ASD) identifier when issuing a directive for the physical delivery of the reserves.
- Dispatching supplemental and spinning reserve resources as necessary due to transmission constraint conditions and including a comment with the dispatched resource in the ancillary service merit order.

- Issuing an ancillary service directive for contingencies inside and outside of the Alberta control area as required.
- Issuing a directive to curtail the Load Shed Service (LSS) loads as required if 1201L trips and the AIES frequency stays at or above 59.5Hz. This may be necessary only if the LSS loads are part of the determining factor in the Alberta contingency reserve calculation.
- If necessary, issuing multiple consecutive ancillary service directives within an hour the ancillary service is offered.
- Not issuing a dispatch to a supplemental or spinning reserve asset that has been issued an ancillary service directive. If a dispatch is attempted, the SC will see the message: "Invalid SR dispatch while ASD is in effect on the unit". This situation may arise when a directive carries into an hour where the ancillary service asset amount (MW) has changed. This new amount cannot be dispatched until the directive is cancelled.
- Once a directive has been issued to zero, immediately dispatching ancillary service assets that have changed their volume or that are no longer required to provide ancillary service. This step is important to align the contractual obligations of the ancillary service providers with the ancillary service dispatches.

4.2 Ancillary Service Provider

The Ancillary Service Provider is responsible for:

- Restating ancillary service declarations 30 minutes before the start of the hour, if possible. This will ensure that restated active supply type assets will be dispatched. At 15 minutes before the start of the hour, the SC will have ancillary services dispatched. Ancillary service providers restating DACs after this time need to call the SC to inform him of the change in their ancillary service declarations. The SC will then assess at what time the changed asset can be dispatched.
- Making available the amount (MW) in an ancillary service dispatch by the indicated dispatch time.
- Declining a dispatch, received with less than 15 minutes to the dispatch time, to which they are unable to comply. The ancillary service provider will then immediately call the SC to explain the reason for declining the dispatch at which time the SC will assess if another asset will be dispatched or if the asset will be re-dispatched with 15 minutes to the dispatch time.
- Physically delivering the amount (MW) in an ancillary service directive within 10 minutes of receiving an ancillary service directive.
- Restating energy issued an ancillary service dispatch from the ancillary services merit order if the energy is also offered into the energy market merit order.
- Restating an asset offered in the ETS ancillary service declarations any time its availability or quantity changes, and give the reason for the change.
- When restating resources in the backstop portfolio, supplemental and spinning reserve providers within the Alberta control area that have a backstop contract will indicate which one of the following situations made the restatement necessary:
  - Local emergency at the Ancillary Service Resource facility;

  - Forced outage of the Ancillary Service Resource;
  - Unplanned outage of the Ancillary Service Resource;
  - Planned Unavailability of the Ancillary Service Resource.
- Restating their ancillary service asset availability if an ancillary service dispatch is declined, and give the reason for the change in availability.
- Immediately informing the SC, by telephone, if the obligation amount cannot be met within 10 minutes of an ancillary service directive.
- Notifying the SC immediately, by telephone, if the dispatched amount of spinning or supplemental reserve can no longer be provided, restate their availability, and give the reason for the change in availability.
- Delivering the amount of reserves in an ancillary service directive for up to 60 minutes or until the ancillary service directive is cancelled by the SC, whichever occurs first.
- After accepting an ancillary service directive, notifying the SC immediately, by telephone, if the delivery of the amount (MW) of reserves cannot be continued.
- Restating the asset to reflect actual volumes (MW) and call the SC, if 15 minutes after a directive is cancelled, the provider is unable to provide the ancillary service for which they are dispatched.
- Continuing to supply the supplemental or spinning reserve, after an ancillary service directive is cancelled, for the amount of the directive until a new ancillary service dispatch is received. This is applicable even if the directive level is different from the ancillary service level that the asset offers in the current hour.
- Ensuring ancillary service assets respond as indicated in Figures 1, 2 and 3 when issued concurrent energy market dispatches and ancillary service directives. Figure 1 illustrates the expected response when a generating asset receives an ancillary service directive while ramping down for an energy market dispatch. Figure 2 illustrates the expected response when a generating asset receives an ancillary service directive while ramping up for an energy market dispatch. Figure 3 illustrates the expected response when a generator receives an ancillary service directive and receives a dispatch down at the same time or within 10 minutes of the ancillary service directive.
- Adjusting regulation range to continue to provide the dispatched amount of regulating reserve immediately following an ancillary service directive.
- Complying with SC directives to direct ancillary services resources that are not in the ancillary services market to provide ancillary services unless there is an immediate risk to personnel, equipment safety, environment (including hydrological constraints) or the public.

4.3 Load Shed Service (LSS) providers

The Ancillary Service Provider is responsible for:

- Curtailing the amount of load as directed by the SC within 10 minutes.
- Providing the SC with real-time telemetry of the LSS load available.

- Developing corresponding operating procedures consistent with this OPP.

5. System Controller Procedures

5.1 Dispatching supplemental and spinning reserves

The SC will:

1. Dispatch up all supplemental and spinning reserve assets with an active supply type offered in the ancillary service merit order, unless an asset can cause a risk to system reliability, and identify to the ancillary service provider the:
    a. Dispatch time, which will be no less than 15 minutes from the time of dispatch, unless mutually agreed to with the ancillary service provider.
    b. Amount (MW) of reserve service (SUPG, SUPL or SR) required.
2. Determine the amount of spinning and supplemental reserves needed to meet the contingency reserve requirement using Table 1. Follow the additional instructions as specified in the table notes if applicable.
3. If more spinning reserve is required than is offered in the active supply type, dispatch the ancillary service merit order in the following sequence until spinning reserve requirements are satisfied.
    a. Dispatch standby supply type spinning reserve.
    b. Dispatch standby supply type regulation range. Only raise range qualifies as spinning reserve.
    c. Dispatch backstop supply type spinning reserve.
    d. Dispatch backstop supply type regulation range.
4. If more supplemental reserve is required than is offered in the active supply type, dispatch the ancillary service merit order in the following sequence until supplemental reserve requirements are satisfied.
    a. Dispatch standby supply type spinning or supplementary reserve according to merit order sequence.
    b. Dispatch standby supply type regulation range. Only raise range qualifies as reserve.
    c. Dispatch backstop supply type spinning or supplemental reserve according to merit order sequence.
    d. Dispatch backstop supply type regulation range.
5. When a supplemental or spinning reserve resource with a standby or backstop supply type is dispatched, identify one of the following causes in the dispatch tool comments:
    a. Insufficient resources to meet requirements.
    b. Failure of another resource.
    c. Declined dispatch by another resource.
    d. Transmission constraint.

6. When reserves are dispatched with a standby or backstop supply type, issue dispatches and identify the:
    a. Dispatch time, which will be no less than 15 minutes from the time of dispatch, unless mutually agreed to with the ancillary service provider.
    b. Amount (MW) of reserve service (SUPG, SUPL or SR) required.
7. Continue to dispatch up the ancillary service merit order if the ancillary service provider declines the dispatch.
8. If more supplemental or spinning reserves are required than are offered/dispatched in all portfolios,
    a. direct supplemental or spinning reserve resources that are not offered in the ancillary service market to provide ancillary services with use of the ancillary services dispatch tool with consideration of factors as described in confidential Appendix B. The tool will flag these supplemental or spinning reserve resources as "O" (out of market).
    b. Follow up the directive with a phone call to the supplemental or spinning reserve service provider to confirm.
    c. Adjust the directive volume if required as system conditions change.
    d. Cancel the directive when it is not required.
    e. Enter in the shift log the details of the directive including reasons, times and participant names, as described in OPP 1301.
9. When reserve requirements are exceeded, assets will be dispatched down in the following sequence while maintaining at least half the reserves as spinning.
    a. Dispatch down backstop supply type regulation range.
    b. Dispatch down backstop supply type supplemental and spinning reserve assets according to the ancillary service merit order sequence.
    c. Dispatch down standby supply type regulation range.
    d. Dispatch down standby supply type supplemental and spinning reserve assets according to ancillary service merit order sequence.

5.2 Issuing an ancillary service directive for delivery of supplemental and spinning reserve energy

The SC will:

1. Determine the required amount of contingency reserve to be issued ancillary service directives.
2. Determine the volume of demand for each supplemental and/or spinning reserve asset that will receive an ancillary service directive.
3. Issue the directive for each of the selected reserve assets and include asset being issued an ancillary service directive, the type of ancillary service to be supplied and the volume (MW) of demand required. The message issued to the ancillary service provider will indicate the volume of demand being directed as well as the remaining volume still dispatched on spinning or supplemental reserve.

4. Issue directives to increase or decrease the amount of supplemental and/or spinning reserve delivered according to step 3.

5.3 Canceling an ancillary service directive for delivery of supplemental and spinning reserve energy

The SC will:

1. Issue an ancillary service directive for zero to all the supplemental and spinning reserve assets within 60 minutes from the time the ancillary service directive was issued.
2. Immediately dispatch ancillary service assets that have changed their volume or are no longer required to provide ancillary service.
3. Issue new directives to dispatched assets if required.

5.4 Issuing a directive to curtail LSS loads

The SC will:

1. Determine if 1201L has tripped.
2. Determine if the SUPL and SR reserves are sufficient, or if all or some of the LSS loads must be curtailed, in order to allow the AIES to recover from the disturbance and meet the DCS requirement.
3. If LSS loads must be curtailed, determine the volume of curtailment for each provider by dividing the total required volume on a pro-rata basis.
4. Call each provider and issue the directive verbally, specifying the amount of the curtailment and that it must be completed in 10 minutes.
5. Call the providers to cancel the directive when the DCS event has been restored.
6. Log the event in the shift log (see OPP 1301) under the directive category, including the start and stop time, and the name and MW volume of load curtailment for each provider. Do not post it on web.

6. Figures and Tables

Figure 1

Generator is dispatched off and receives ASD before reaching energy market dispatch level.

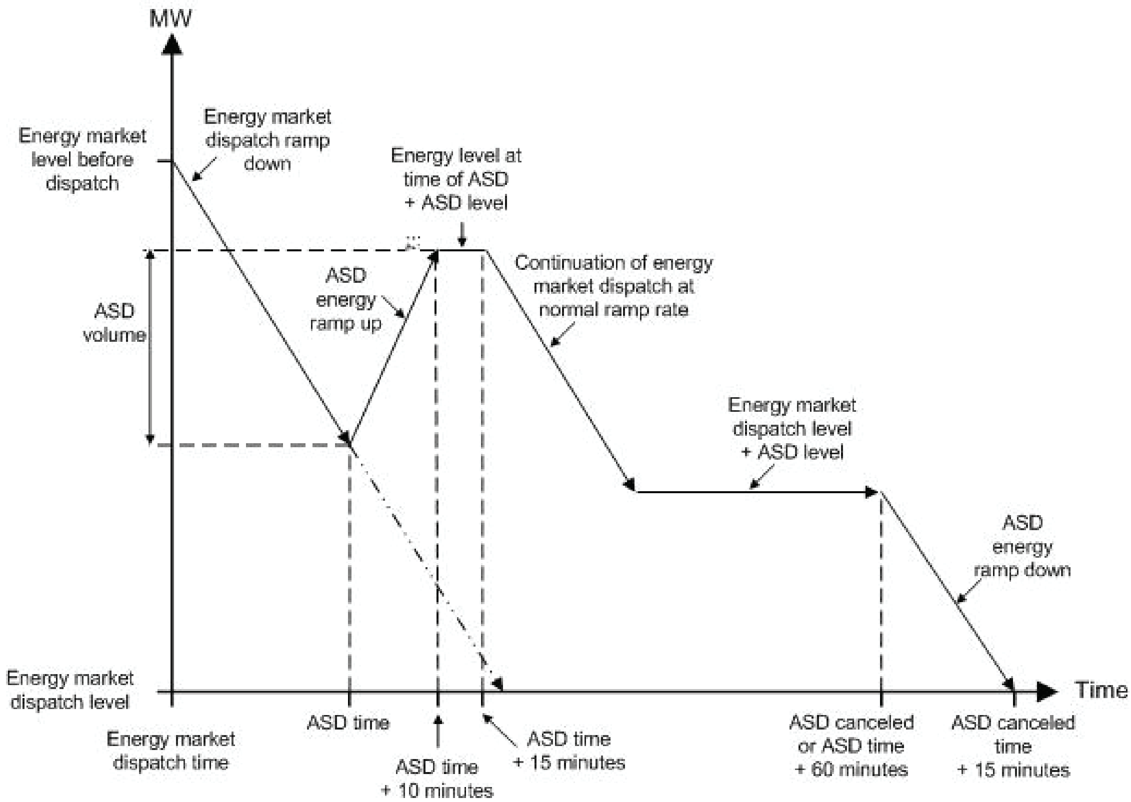


Figure 2

Generator is dispatched on and receives ASD before reaching energy market dispatch level.

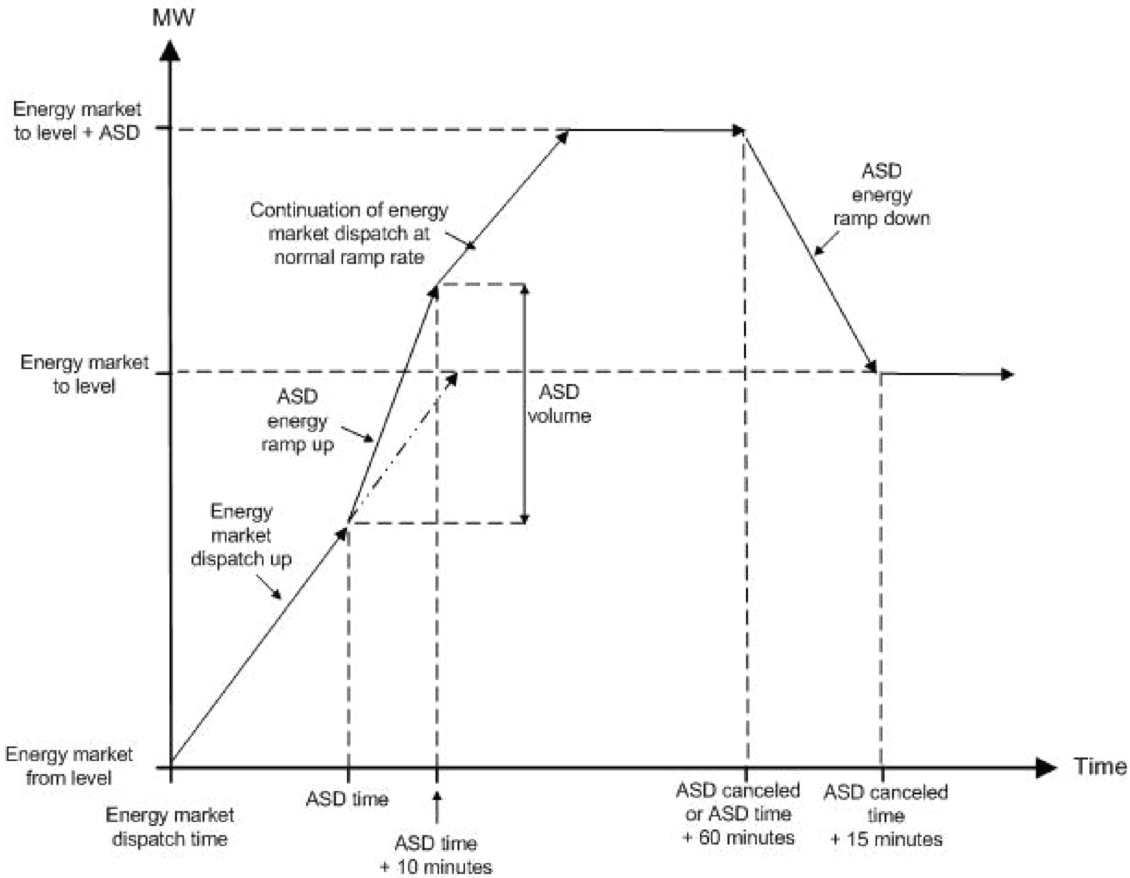


Figure 3

Generator receives an ASD and receives a dispatch off at the same time or within 10 minutes of the ASD.

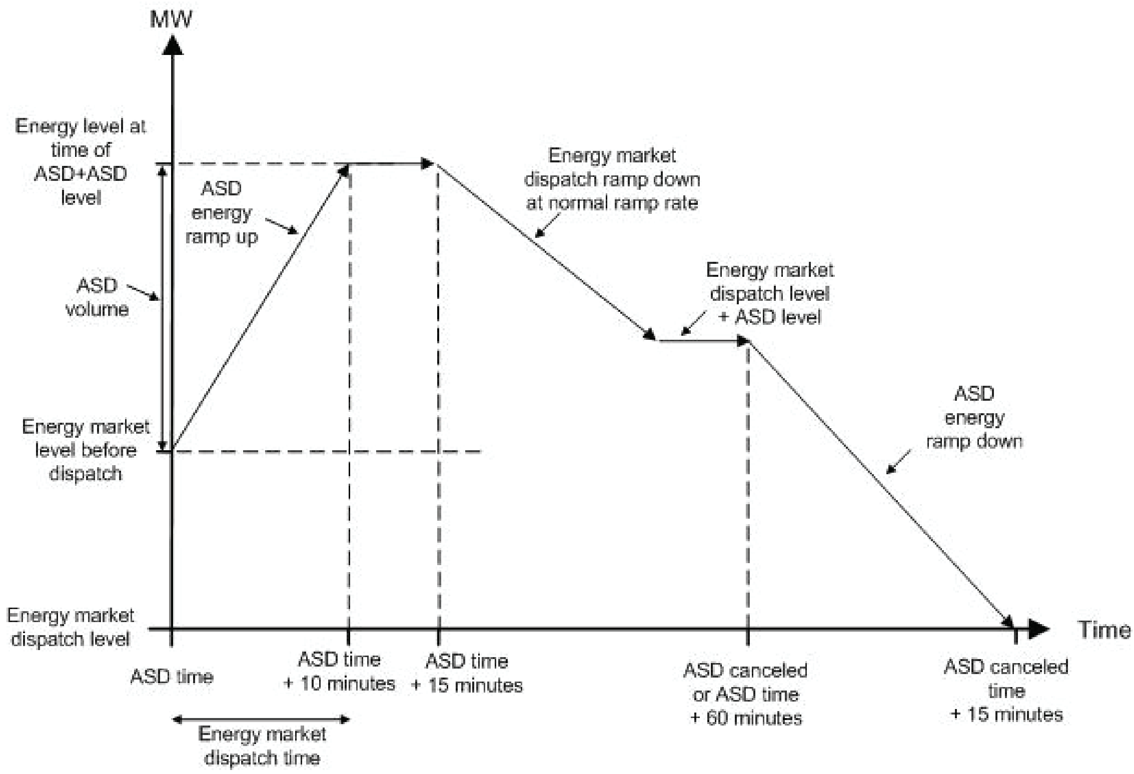


Table 1

Alberta contingency reserve requirements

System Conditions	Alberta Contingency Reserve Requirements
1201L in service and 5L92 (Cranbrook – Selkirk) in service	The greater of: 1. Net import on the AB-BC interconnection – Armed ILRAS – LSS loads on line 2. Alberta's CRO to NWPP (see note 1)
1201L in service and 5L92 (Cranbrook – Selkirk) not in service	The greater of: 1. Alberta's single largest generator contingency + Net import on the AB-BC interconnection – Armed ILRAS – LSS loads on line (see note 2) 2. Alberta's CRO to NWPP (see note 1)
1201L in service and 2L294 (Cranbrook – Nelway) not in service	The greater of: 1. Net import on the AB-BC interconnection + Cranbrook \ Natal \ Ford-ELK area loads – LSS loads on line (see note 3) 2. Alberta's CRO to NWPP (see note 1)
1201L not in service	The greater of: 1. Alberta's single largest contingency + Net import on the AB-BC interconnection – Net export on the AB-BC interconnection 2. Alberta's CRO to NWPP (see note 1)

Notes:

1. Alberta's CRO to NWPP is the sum of 5% of Alberta's firm load responsibility served by hydro and wind generation and 7% of Alberta's firm load responsibility served by thermal generation. For details on firm load responsibility see OPP 406.
2. Upon a generator contingency in the AIES, the protection scheme on 2L294 may initiate a transfer trip to 1201L. Therefore, the net impact to Alberta is the sum of the generator contingency and the loss of BC import, minus armed ILRAS and LSS loads.
3. A contingency on 5L92 will result in the loss of BC import and the Cranbrook / Natal / Ford-ELK loads being picked up by the Alberta control area. The BCH Operator will provide to the System Controller hourly the MW flow on 5L92 measured at the Selkirk substation. The System Controller then calculates: [Cranbrook \ Natal \ Ford-ELK load] = [5L92 MW at Selkirk] – [net import on the AB-BC interconnection]. The System Controller will also provide to the BCH Operator the AB-BC interconnection ATC without ILRAS (assume 0 MW ILRAS).

Appendix A. Case Examples of Contingency Reserve Requirements

Introduction

Section 3.2 refers to maintaining sufficient contingency reserve levels to recover from the most severe generating or transmission contingency. Typically the most severe single generation contingency will be considered as 450 MW where that contingency is equivalent to the forced interruption of the Genesee unit #3. It must also be recognized that the magnitude of the generator loading may vary and at times is greater than the maximum continuous rating of the unit. The most severe single transmission contingency is considered to be the BC Interconnection if loaded above 450 MW import.

For each case below, 500 MW of load are assumed not to be firm load responsibility.

For required regulating reserve in the following examples refer to OPP 401.

Case A: 0 MW Import or Export Conditions and 500 kV BC Tie Out of Service

System Load	4793 MW
Imports	0
Exports	0
Firm Load Responsibility	4293 MW
5% Loaded Hydro and wind (assume 321 MW)	16 MW = 5% of 321 MW
7% Loaded Thermal (variable)	278 MW = 7% of (4293-321) MW
5% Hydro and wind + 7% Thermal	294 MW
Largest Single Generation Contingency	450 MW
Contingency Reserve Requirement	450 MW
Spinning Reserve Requirement	225 MW

Case B: 0 MW Import or Export Conditions and 500 kV BC Tie In-service

System Load	4793 MW
Imports	0
Exports	0
Firm Load Responsibility	4293
5% Loaded Hydro and wind (assume 321 MW)	16 MW = 5% of 321 MW
7% Loaded Thermal (variable)	278 MW = 7% of (4293-321) MW
5% Hydro and wind + 7% Thermal	294 MW
Largest Single Generation Contingency	450 MW
Contingency Reserve Requirement	294 MW
Spinning Reserve Requirement	198 MW

Case C: 800 MW Export Condition

System Load	5500 MW
Firm Exports	800 MW
Firm Load Responsibility	5800 MW = 5000 MW (AIES firm load) + 800 MW (firm export)
5% Loaded Hydro and wind (assume 321 MW)	16 MW = 5% of 321 MW
7% Loaded Thermal (variable)	384 MW = 7% of (5800-321) MW
5% Hydro and wind + 7% Thermal	400 MW
Largest Single Generation Contingency	450 MW
Contingency Reserve Requirement	400 MW
Spinning Reserve Requirement	200 MW

Case D: 600 MW Import Condition

System Load	7000 MW
Firm Imports (all via BC tie)	600 MW
Exports	0
Firm Load Responsibility	5900 MW = 6500 MW (AIES firm demand) + 0 MW firm export – 600 MW (firm import)
5% Loaded Hydro and wind (assume 321 MW)	16 MW = 5% of 321 MW
7% Loaded Thermal (variable)	391 MW = 7% of (5900-321) MW
5% Hydro and wind + 7% Thermal	407 MW
Largest Single Generation Contingency	450 MW
Contingency Reserve Requirement	407 MW
Spinning Reserve Requirement	204 MW

Load Connected to RAS (BC tie) is 200 MW.

Case E: 350 MW Import, 150 MW Export Condition

System Load	6500 MW
Firm Imports	150 MW
Firm Exports	350 MW
Firm Load Responsibility	6200 MW = 6000 MW (AIES firm demand) +350 MW (firm export) – 150 MW (firm import)
5% Loaded Hydro and wind (assume 321 MW)	16 MW = 5% of 321 MW
7% Loaded Thermal (variable)	412 MW =7% of (6200-321) MW
5% Hydro and wind + 7% Thermal	428 MW
Largest Single Generation Contingency	450 MW
Contingency Reserve Requirement	428 MW
Spinning Reserve Requirement	214 MW

Appendix B. Factors to Consider when Directing Out-of-Market Ancillary Services Resources is Required

The information in this appendix is confidential. To view the appendix, click the link below and then provide the password.

View Appendix B

7. Revision History

Issued	Description
2004-03-03	Supersedes 2003-07-28
2003-07-28	Revised to ISO Operating Policies and Procedures

404 ANCILLARY SERVICE DISPATCHES AND DIRECTIVES

1. Purpose

To provide policies for the System Controller (SC) and Participants, and procedures for the System Controller, in the exchange of ancillary service dispatch and directive messages and responses.

2. Background

Since the deregulation of the Alberta electrical retail market, the number of Participants and the volume of SC dispatches have increased significantly. To improve efficiency in providing dispatches, directives, and system messages to Participants, the ISO has implemented an Automated and Dispatch and Messaging System (ADAMS). This Internet-based system is the primary method for the SC to issue dispatches, directives and system messages. Voice communication is still required in some circumstances and will serve as a back-up dispatch and messaging method.

3. Policy

- Each asset on the ancillary service merit order will have one active user who has permission to accept or reject ancillary service dispatches, and/or to acknowledge ancillary service directives on ADAMS, except as noted below.
- EXCEPTION: Ancillary service directives for external spinning and supplemental reserves from BC Transmission Corporation (BCTC) will be issued via voice communication with the host control area in accordance with procedures outlined in OPP 403.
- Each asset on the ancillary service merit order may have one or more carbon copy users who have permission to receive and view ancillary service dispatches and/or directives, but not to accept or reject dispatches, or to acknowledge ancillary service directives.
- An active or carbon copy user will receive ancillary service dispatches and/or directives only for assets for which permission has been assigned.
- The ISO will administer the user list and permission assignment for all ISO assets eligible to receive ancillary service dispatches or directives.
- An active or carbon copy user is required to have a computer system and communication connection meeting the requirements listed in Table 2 of OPP 003.2, Automated Dispatch and Messaging System (ADAMS).
- Each user will be assigned a unique username for logging on to ADAMS. The username is password protected.
- A user must be logged on to the ISO ADAMS web server in order to receive real time ancillary service dispatches and/or directives via ADAMS.

- If the ADAMS web server does not receive the active user's response to an ancillary service dispatch within the required time, the dispatch message will time out. The active user must contact the SC immediately.
- If the ADAMS web server does not receive the active user's response to an ancillary service directive within the required time, the directive message will time out. The active user must contact the SC immediately.
- The status of an ancillary service dispatch or directive is identified on the System Controller dispatch tool by one of the following symbols:

I (initiated)	The dispatch or directive has been issued.
P (pending)	The dispatch or directive has been received by the participant web server.
A (accepted)	The active user has accepted the dispatch or acknowledged the directive.
F (future dispatch)	The active user has accepted the dispatch that has a future dispatch time.
R (rejected)	The active user has declined the dispatch.
T (time out)	The participant web server has not received a response for the dispatch or directive within the required time.

- Depending on the ancillary service dispatch and the active user's response, the asset's ancillary service dispatched MW volume will be as listed in Table 1 and Table 2.
- Depending on the ancillary service directive and the active user's response, the asset's ancillary service directive status and MW volume will be as listed in Table 3 and Table 4.
- When an AS dispatch is issued to an asset to a higher MW level and a reject response is received, the dispatch tool puts a limit on the MW volume for that asset for that AS service. The limit starts at the dispatch time and is removed when the participant restates the asset's availability or at the end of the hour, whichever occurs first. The limit will be the dispatched AS level of the asset at the dispatch time. When the limit is in effect, the dispatch tool does not allow an AS dispatch to the asset to exceed the limit for the same AS service.

4. Responsibilities

4.1 System Controller

- The SC will issue ancillary service dispatches and directives via ADAMS.
- The SC will issue ancillary service dispatches and directives manually via voice communication when they cannot be issued by ADAMS.

4.2 Participants

- Participants will ensure that the active user's computer system is capable of receiving ancillary service dispatches and/or directives via ADAMS when the Participant has an asset offered in the ancillary service merit order.
- Participants must respond to ADAMS ancillary service dispatches and/or directives within the required time as described in OPP 003.2, Automated Dispatch and Messaging System (ADAMS).

- Participants must restate the asset's ancillary service capability immediately if it is changed from its offer. Restatement is submitted on the AESO Energy Trading System (ETS).
- Participants must contact the SC immediately to provide reasons for rejecting an ancillary service dispatch.
- Participants must inform the SC immediately if they are not, or will not be, capable of receiving ADAMS ancillary service dispatches and/or directives.
- Participants must contact the SC immediately if a dispatch or directive has been missed or has been responded to in error.

5. System Controller Procedures

5.1 Ancillary service dispatches by ADAMS

The SC will:

1. On the ancillary service dispatch tool, enter the required amount of contingency reserves and regulating reserves in the corresponding Requested MW field.
2. Confirm that the popup Issue Dispatch dialog box displays a list of assets with the service types and MW volumes, each with the Adams option selected.
3. If a dispatch has to be issued manually, de-select the Adams option and the selection will change to Manual. Proceed to Section 5.3.
4. Note that the indicated in Expected Time is by default the current time plus 15 minutes or start of the next hour, whichever is sooner. If a different dispatch time is required, make the adjustment to the Expected Time. Note that the same Expected Time will apply to all the assets with the Adams option selected on the display.
5. Verify the other information on the popup dialog box and then click the Adams button.
6. Confirm that the web status for each of the dispatched asset changes to I.
7. If and when the ADAMS web server has received the dispatch message observe that the web status changes to P.
8. If the dispatch message has not been received by the ADAMS web server within the programmed pre-set time limit, observe that the web status changes to D. Proceed to re-issue the dispatch manually (see Section 5.3).
9. According to the dispatch and the active user's response, observe the changes in the web status and the dispatched MW volume as shown in Table 1 or Table 2 The comment column shows any required action by the Participant and/or the System Controller.
10. Verify on the dispatch tool Summary display that the Dispatched volumes for the ancillary services have been updated accordingly at the dispatch time/Expected Time.

5.2 Ancillary services directives by ADAMS

To issue an ancillary service directive for external spinning and supplemental reserves from BCTC, the SC will contact the host control area as detailed in OPP 403.

For all other ancillary service directives, the System Controller will:

1. On the ancillary service dispatch tool toolbar, click on the Directives icon.

2. Note that an Issue Directive display will pop up showing a list of assets that are currently dispatched for ancillary services.
3. Select the Adams option for each asset that is to be issued an ancillary service directive (ASD) and adjust the ASD volume.
4. Notice that the default time of the directive is the current time. Adjust if required.
5. Verify the other information in the popup dialog box and click the Adams button.
6. Confirm that the web status changes to I.
7. If and when the participant web server has received the message, confirm that the web status changes to P.
8. According to the directive and the active user's response, confirm the changes in the dispatch tool display as shown in Table 3 and Table 4. The comment column shows any required action by the Participant and/or the System Controller.

5.3 Manual ancillary service dispatches

When the ancillary service dispatch cannot be issued by ADAMS, the SC will:

1. Issue the dispatch to the active user via telephone communication.
2. On the ancillary service dispatch tool, on popup Issue Dispatch dialog box, de-select the Adams option for the asset. Notice that the option changes to Manual and a dispatch time is shown next to the asset.
3. Notice that the dispatch time is the current time plus 15 minutes by default. Adjust the dispatch time to the time agreed to with the active user.
4. If the dispatch time is a future time, confirm that the web status immediately changes to F.
5. At the dispatch time, notice that the web status changes to A, and the dispatched MW volume are updated according to Table 1 or Table 2

5.4 Manual ancillary service directives

When the ancillary service directive cannot be issued by ADAMS, the SC will:

1. Issue the directive to the active user via telephone communication.
2. On the ancillary service dispatch tool, the popup Issue Directive dialog box, de-select the Adams option for the asset. Notice that the option changes to Manual and a dispatch time is shown next to the asset.
3. Notice that the dispatch time is the current time by default. Adjust the dispatch time if required.
4. Confirm that the web status immediately changes to A, and the ASD status, the dispatched MW and the ASD MW volume are updated accordingly.

6. Figures and Tables

Table 1

Ancillary services (AS) dispatch for an asset to a new level that is higher than the current level

Active User Response	Web Status (W?)	Asset AS Dispatched MW volume	Comment
Accept • before the dispatch time • at the dispatch time	 F A	 Unchanged at the current level Change to the new level	
Reject • before the dispatch time • at the dispatch time	 R R	 Unchanged at the current level Unchanged at the current level	 Participant to contact SC to provide reason for reject and to restate its AS availability A MW limit will be applied at the current level by DT at the dispatch time The participant is responsible to provide AS at the current level
No response	T	Unchanged at the current level	Participant to contact SC or, time permitting, SC will call Participant

Table 2

Ancillary services (AS) dispatch for an asset to a new level that is lower than the current level

Active User Response	Web Status (W?)	Asset AS Dispatched MW volume	Comment
Accept • before the dispatch time • at the dispatch time	 F A	 Unchanged at the current level Change to the new level	
Reject • before the dispatch time • at the dispatch time	 R R	 Unchanged at the current level Changed to the new level	 Participant to contact SC to provide reason for reject and to restate its availability The participant is responsible to provide AS at the new level
No response	T	Unchanged at the current level	Participant to contact SC or, time permitting, SC will call Participant

Table 3

Ancillary services directive for volume greater than 0 MW

Active User Response	Web Status (W?)	ASD Status (ASD?)	ASD MW Volume	Comment
Acknowledge	A	Y	Change to the new level	
No response	T	Unchanged from the current status	Unchanged at the current level	Participant to contact SC or, time permitting, SC will call Participant

Table 4

Ancillary services directive for 0 MW

Active User Response	Web Status (W?)	ASD Status (ASD?)	ASD MW Volume	Comment
Acknowledge	A	N	Change to 0	
No response	T	Y	Unchanged at the current level	Participant to contact SC or, time permitting, SC will call Participant

7. Revision History

Issued	Description
2004-08-04	Supersedes 2004-03-03
2004-03-03	Approved for interim implementation
2003-07-28	Revised to ISO Operating Policies and Procedures

705 SHORT TERM ADEQUACY ASSESSMENTS

1. Purpose

To define the policy and procedures for the System Controller (SC) when determining short-term adequacy (STA) of available supply to meet the system load requirements and when directing available supply.

2. Background

On occasion, there are insufficient energy offers in the energy market merit order to meet the load requirements of the AIES. The SC must follow the steps identified in OPP 801 Supply Shortfall to manage this condition. OPP 801 identifies a number of steps to be taken to reduce the possibility of shedding firm load.

STA assessment is performed by the AESO to determine if there will be a supply shortfall. If the STA assessment indicates that there will be a supply shortfall, then sufficient notice must be given to pool participants with long lead time generating asset to allow for the start-up times of such assets

3. Policy

- An STA assessment must be performed for each hour of the current trading day and for each hour of the following six trading days to determine if there will be an adequate supply to meet Alberta Internal Load (AIL). The STA assessment must be performed as follows:

  The sum of the following:

  – AC from all generating assets in Alberta equal to or greater than 5 MW with a start-up time ≤1 hour or with a submitted start time at or before the period being assessed,

  – Estimated output from wind power facilities (Table 1),

  – Estimated amount of Price responsive load (Table 1),

  – Estimated amount of demand opportunity service (DOS) load that will be curtailed (Table 1),

  – On-site generation (Table 3) that supplies behind-the-fence load and submits AC as a net-to-grid value,

  – Import available transfer capability (ATC) on the Alberta-BC Interconnection,

  – Import ATC on the Alberta-Saskatchewan Interconnection.

  Minus each of the following:

  – The peak forecast load from the day-ahead forecast of AIL,

    – 3.5% of forecast load to account for ancillary service requirements and directing supplemental and excess spinning reserves,

    – Constrained down generation, with the exception of wind constraints.

- If the above calculation results in a negative number then it would indicate inadequate supply for the hour, and that the following actions may be required:
    - Issuing a message to pool participants that a supply shortfall is anticipated and waiting for voluntary commitment of generation.
    - Directing pool participants with long lead time generating assets and available generation in Table 2 to start.
    - Generating assets in the long-lead-time energy list and Table 2 will not be directed to start if the required start-up time of the generating asset is greater than the time for the supply shortfall event.
- If directed by the SC, the pool participant must bring the long lead time generating asset to the directed level and remain there until further directed by the SC.
- The pool participant that has received a long lead time energy directive may:
    - Accept the long lead time energy directive and become eligible for compensation as described in Appendix 7 of ISO Rules, or
    - Decide and inform the SC of its decision to offer the long lead time generating asset in the energy market, and be dispatched according to the energy market merit order , in which case it must meet the time and quantity requirements of the long lead time energy directive, by:
        - submitting to the ISO at least two hours prior to the beginning of the settlement interval the time of day that the long lead time generating asset will be synchronized to the AIES, , or
        - updating the AC for those long lead time generating assets synchronized to the AIES whose AC was excluded due to asset constraints (Table 2), at least two hours prior to the beginning of the settlement interval.
- for the above long lead time generating assets for which the pool participant has indicated its intention to start or update its AC, the SC will cancel the long lead time energy directive and dispatch them according to the energy market merit order. These long lead time generating assets will not be eligible for compensation as described in Appendix 7 of the ISO Rules.
- long-lead-time generating assets are sorted in this priority order:
    1. Shortest start-up time
    2. Largest incremental AC
    3. Minimum run time
    4. Loss factor
- Directives for energy from the long-lead-time generating assets will be issued commensurate with the longest lead time of these generating assets, that are available to deliver energy by the time the energy is required, plus 1 hour if conditions permit.

4. Responsibilities

4.1 ISO

- The ISO must update the ISO Rules and the OPPs as required.

System Controller

- The SC must perform STA assessments to determine if long lead time generating assets need to be directed to start.
- The SC must direct pool participants to start long lead time generating assets according to the priority order listed in section 3.
- If operating conditions unexpectedly change and long lead time generating assets that were directed to start are affected, the SC must cancel or adjust directives to the pool participant as required.

4.2 Pool Participants

- If a pool participant, that has received a long lead time energy directive, decides to participate in the energy market, it must call the SC to inform it of its decision.
- If the pool participant decides to start the long lead time generating asset, it must submit a start time for its generating asset in automated dispatch and messaging system (ADAMS) equal to or greater than the required lead time to start the generating asset at least two hours prior to the beginning of the settlement interval.
- If the pool participant's generating asset (Table 2) is already synchronized to the AIES but does not have long lead time energy reflected in the AC of its offer in the ETS, the pool participant must restate its AC for the settlement intervals and submit the restatement equal to or greater than the required lead time to start the long lead time generating asset(s) at least two hours prior to the beginning of the settlement interval.
- The pool participant must take appropriate steps to make the energy available for the settlement interval time indicated in the long lead time energy directive and notify the SC before synchronizing the long lead time generating asset to the AIES. When the long lead time generating asset comes on-line the pool participant must ramp its generating asset to its directed level and remain there until further directed by the SC.

5. System Controller Procedures

5.1 STA Assessment

When a STA assessment indicates there may not be adequate supply to meet AIL, the SC must:

1. If there is a change to the import ATC on either the BC or Saskatchewan interconnection, repost ATC.
2. Ensure that a transmission limiter has been entered in the dispatch tool (DT) for any generating asset that has been limited due to transmission constraint.
3. From the Dispatch Tool (DT) open the supply adequacy report and observe the supply adequacy value provided for each hour.
4. If all of the hourly supply adequacy values calculated in the supply adequacy report are positive then no additional generating assets are required.

5. If any of the hourly supply adequacy values from the supply adequacy report are negative then notify the AESO personnel as per Table 1 in OPP 1303 (confidential) that a supply shortfall is forecast.

6. Issue the following message from ADAMS corresponding to the first hour that has a negative supply adequacy value and enter into the SC shift log and select the post to web option:

   "A supply shortfall is forecast starting at hh:mm on yyyy-mm-dd. Any generating asset that is planning to start, notify the SC as soon as possible. Refer to the supply adequacy report on the ISO website."

7. If any of the hourly supply adequacy values from the supply adequacy report are negative and transmission maintenance can be canceled to remove the generation constraints as described in Section 5.1 in OPP 801, then add the amount of increased generation and/or increase in import ATC to the supply adequacy value.

8. If it is forecast that all energy from the long-lead-time generating assets identified in step 9 below and incremental import ATC available on the AB-BC interconnection by arming available import load remedial action scheme (ILRAS) will be required to meet AIL, then refer to Section 5.1 in OPP 801 to ensure the planning steps for managing a supply shortfall are completed. To determine the incremental Alberta-BC import ATC using ILRAS load as a factor for the period being assessed, perform the following:

   a. Multiply the forecast load by 0.023 to get an estimated ILRAS load value.

   b. Refer to Table 1 in OPP 312 to determine the import ATC level corresponding to the combined ILRAS and LSS value and forecast system load.

   c. Refer to OPP 304 and take the lesser of the import ATC transfer limit and the import ATC limit determined with the use of ILRAS and LSS and subtract the forecast import ATC limit for the period being assessed.

9. Go to Table 2 and look up the EMS display for each generating asset as indicated in the table, and if any of the "Generators" listed in the table are off-line then phone the pool participant whose "Generator" is off line and ask if it has any long lead time energy that has not been reflected in its currently offered available capability in the energy market merit order. Advise the pool participant that this is not a directive to start available generation. If long lead time energy is available, then ask:

   - What amount of additional long lead time energy would be available?
   - What lead time is required to start the "Generators"?
   - What is the minimum run time of the "Generator s"?

   If there is sufficient time to start the "Generators" to assist in the anticipated supply shortfall, then include this amount when making the assessment in step 8.

10. Wait a reasonable period as conditions permit for any voluntary response to the ADAMS message issued in step 6.

    - If a pool participant notifies the SC that it is planning to start a generating asset, then request the pool participant to enter the generating asset start time in ADAMS as soon as possible in accordance with the ISO Rules with the exception of generating assets identified in Table 2.

- If a pool participant with a generating asset identified in Table 2 is planning to start a "Generators" with a start-time greater than 1 hour, the pool participant may restate its AC in accordance with the ISO Rules as applicable for the appropriate hours to reflect their new offer amount.
- When a pool participant has submitted a start time or restated their AC for its generating asset, then its restated AC will be used in the supply adequacy calculation and a new supply adequacy value will appear in the supply adequacy report.

11. If there is sufficient response from pool participants and the supply adequacy values become positive, or at any time the supply shortfall is no longer forecast, then:
    a. Issue the following message in ADAMS to all pool participants and enter it into the SC Shift Log and select the post to web option:

       "A supply shortfall is no longer forecast."
    b. Go to step 17.
12. If there is insufficient response from pool participants and the supply shortfall is still anticipated, go to the first hour with a negative supply adequacy and open the long-lead-time energy list of generating assets.
13. Select generating assets to direct to start from the long-lead-time energy list that is prioritized according to the order in which they are to be directed to start (from bottom to top). If additional energy is also available from the generating assets identified in Table 2, then direct these "Generators" and the assets in the long lead time energy list to start based on the following priority order:
    - Shortest start-up time
    - Largest incremental AC
    - Minimum run time
    - Loss factor
14. Perform the following when selecting and directing a generating asset to start:
    - Direct generating assets in order to turn the supply adequacy value to a positive number.
    - Direct the generating asset(s) to start at the time plus 1 hour if conditions permit, in order of priority according to step 13.
    - Ensure that if the pool participant has received a directive to start a long lead time generating asset and has decided to offer the generating asset in the energy market according to the ISO rules, cancel the long lead time energy directive and dispatch the generating assets according to the energy market merit order.
    - If the pool participant does not intend to participate in the energy market, it must not reflect changes to its AC or start time to reflect the directive.
    - Include long lead time energy in determining volume of Dispatch Down Service (DDS) in accordance with OPP 101.
15. Make a note in the SC Shift Log of the generating assets that were directed to start and their response but do not post it to the ISO web.

16. If insufficient generating assets are committed to start from the long-lead-time energy list and Table 2, then add the incremental import ATC available on the Alberta-BC interconnection by including ILRAS load as a factor, as determined in step 7, to the supply adequacy number.
17. In the supply adequacy report double-click on the line of the next hour with a negative supply adequacy value and repeat steps 12 through 16.
18. If there is an unanticipated reduction in supply, then repeat the STA assessment.
19. If there is an unanticipated increase in supply, such as a large thermal generating asset coming back on-line earlier than expected, and if generating asset(s) from the long-lead-time energy list were directed to start and are no longer required, then cancel the long lead time energy directive and issue the following message in ADAMS to all pool participants and enter it into the SC Shift Log and select the post to WEB option: "A supply shortfall is no longer forecast."

5A. Effective Date

The specified amendments cited in Application No 1605243 for Operating Policy and Procedure will be effective 30 calendar days after the date to be determined by the Commission for, collectively, ISO rules consisting of G1 definitions, 6.3.5.1, 6.3.5.2, 6.3.6.2, 6.3.6.3 and Appendix 7 (collectively the "**LLTD Rule**")

6. Figures and Tables

Table 1

Values to use in short term adequacy calculation

Item	Value (MW)*
Wind Power Facilities output	145[1]
Price Responsive Load	200[2]
DOS Load	20[3]

Note:

1. A fixed value will be used for the time period beyond six hours. For the time period within six hours, an estimated value based on historical data analysis will be used.
2. A fixed number is used for period beyond the next day. For the current and next day, it is the current real-time value.
3. Most DOS loads are price responsive; therefore, this number is less than the actual amount of DOS that is normally on the system

*These values and information within the corresponding notes are based on experience or best judgment and will be changed in the supply adequacy report on the ISO website if values closer to actual are identified..

.

Table 2

Generating assets that have long lead times greater than 1 hour that may not be able to declare all their generation as AC in the energy trading system

Confidential: Click link below to view

Table 3

On-site generation that provides AC as a net-to-grid value

Confidential: Click link below to view

View confidential tables

7. Revision History

Issued	Description
2012-08-07	Supersedes 2010-03-03, replaced AIES demand to system load
2010-03-03	Supersedes 2009-02-19
2009-02-19	Supersedes 2009-11-13
2009-11-13	Supersedes 2008-03-04
2008-03-04	Interim OPP supersedes 2007-12-03; only confidential information changed
2007-12-03	Supersedes 2007-01-17
2007-01-17	Approved for interim implementation; supersedes 2005-03-30
2005-03-30	Supersedes 2004-12-22
2004-12-22	New Issue, approved for interim implementation 2004-12-21

Operating Policies and Procedures

Emergency System Operations
OPP 801

Issue: 2012-08-07

Supersedes: 2010-03-03

801 SUPPLY SHORTFALL

1. Purpose

To define the procedures for the System Controller (SC) to follow and to specify measures to be taken by market participants involved in responding to a supply shortfall condition in Alberta in order to maintain system reliability.

2. Background

A supply shortfall is a condition when there is insufficient energy offered in the energy market to meet the Alberta Internal Load (AIL). Various events such as generation and/or transmission contingencies, energy market deficiencies, or unexpected demand levels in Alberta can result a supply shortfall. Supply shortfalls could ultimately require curtailment of firm loads in order to maintain system reliability. However, before curtailing firm loads, other measures may be undertaken as outlined in this OPP.

3. Policy

- Instructions for issuing energy emergency alerts and firm load directives are provided in OPP 802.
- Instructions for determining the short term adequacy (STA) of available supply to meet the system load requirements and requesting or directing available supply are provided in OPP 705.
- The import load remedial action scheme **(**ILRAS) must be armed for the hours when it is anticipated by the SC that additional energy will be required above the amount made available from long lead time generating assets and Table 2 in OPP 705. Criteria for use of energy from these generating assets are included in OPP 705 Short Term Adequacy Assessments. If all energy from these generating assets is anticipated to be required in the future hour, then the Alberta–BC import ATC will be revised and posted for that future hour up to the level that includes ILRAS loads as one of the factors for determining the import ATC. Details on ILRAS arming and corresponding Alberta-BC import ATC are included in OPP 312.
- The minimum requirement for regulating reserve (refer to OPP 401) must be maintained under all circumstances, even if firm or non-price responsive load needs to be shed.
- If required, the SC may skip one or more steps in Table 1 when managing a supply shortfall in order to meet the Alberta Reliability Standard regarding control performance.
- If the SC does skip one or more steps in Table 1 when managing a supply shortfall, the SC must return to the skipped step(s) and reduce the requirements for energy from later steps if time and operating conditions permit.
- A market participant who voluntarily curtails load or increases energy supply must notify the SC when it can no longer continue to do so.
- Owners of electric distribution systems and retailers may receive an appeal from the SC to voluntarily curtail any non-essential or non-bid loads.

- During normal system operating conditions generating assets will not exceed the maximum authorized MW (MAM) level that has been established to satisfy reactive power requirements; however during a supply shortfall event these levels may be permitted to be exceeded as per step 18 in Table 1.
- When the SC gives permission for a generating asset to operate to a gross MW level above the MAM then the plant operator can operate the generating asset up to that level. This additional energy above MAM is not to be restated in the energy market.
- When the plant operator is notified by the SC that the energy supplied above MAM is no longer required, then the plant operator must return the generating asset to the energy market dispatch level.
- During a supply shortfall and in accordance with this procedure, valid e-tags submitted for the current or next scheduling hour for import energy that do not have a corresponding energy offer in the energy market merit order, must be approved by the SC up to the posted available transfer capability (ATC) limit.

4. Responsibilities

4.1 ISO

- The ISO must review and update this OPP as required.

System Controller

- The SC must follow this OPP when managing a supply shortfall or when a supply shortfall is anticipated.
- The SC must maintain the required amount of regulating reserves (refer to OPP 401) during a supply shortfall event.

4.2 Transmission Facility Owners (TFOs)

- TFOs must respond to SC directive to cancel transmission outages.

4.3 Owners of Electric Distribution Systems and Retailers

- Owners of electric distribution systems will make best efforts to achieve a 3% voltage reduction on their electric distribution systems when requested by the SC. Voltage will only be restored following notification by the owners of electric distribution systems to the SC.

4.4 Generation Facility Owners (GFOs)

- GFOs will make best efforts to reduce any non-essential station service loads when requested by the SC. Loads will only be restored following notification by the SC. Compliance with this request is on a voluntary basis.

5. System Controller Procedures

5.1 Planning in anticipation of a supply shortfall

The SC must:

1. When it is anticipated that all supply in the energy market merit order will be dispatched, notify the AESO personnel as described in OPP 1303 (confidential).

2. If step 10 in Table 1 is anticipated to be reached, cancel transmission maintenance to remove generation constraints or increase import ATC on the Alberta-BC and/or Alberta-Saskatchewan interconnection. Issue directives to TFOs to cancel transmission maintenance within Alberta and request BCTC or SPC to cancel transmission maintenance on their respective systems that reduce import ATC to Alberta.
3. Perform a STA assessment to determine if additional generating assets need to be directed to start; refer to OPP 705.
4. If additional energy is anticipated to be required above the amount available from generating assets in the long-lead-time energy list and Table 2 in OPP 705, then remove 0 MW override on ILRAS value on display #6975 and include ILRAS load as a factor to determine the maximum Alberta-BC import ATC in accordance with OPP 304 and Table 1 in OPP 312.
   a. Re-post the import ATC to the level that is required to manage the supply shortfall event up to the maximum ATC limit for the future hour(s) when this energy is required.
   b. Notify BCTC to have the new ATC posted on the OASIS site.
   c. Issue a dispatch to AltaLink to arm the required ILRAS load according to the import levels and provide the time when the ILRAS loads are to be armed.
5. Carry out an assessment of supply shortfall by following through all steps listed in Table 1 assuming imports at the ATC limit. If it is assessed that shedding of firm load is imminent, notify the AESO operations person on call at least 4 hours in advance to arrange for AESO Stakeholder Relations and Communications to issue a public appeal to reduce electrical energy consumption.
6. Allow for 1 hour notice if it is anticipated that the demand opportunity service (DOS) 1 hour loads will be curtailed (step 7 in Table 1).
7. Determine when export ATC on the BC and Saskatchewan interconnections are to be posted to 0 MW (step 6 in Table 1) so new export ATC levels can be posted 1 hour in advance.
8. If the SC reasonably anticipates an energy emergency alert 1 or 2 will be reached, notify the Vancouver Reliability Coordinator (VRC), British Columbia Transmission Corporation (BCTC), and SaskPower.
9. Allow for 1 hour notice if it is anticipated that the AESO Voluntary Load Curtailment Program (VLCP) loads will be dispatched off (step 24 in Table 1).

5.2 Managing a supply shortfall

The SC must follow the steps identified in Table 1 under the column heading of "Supply Shortfall Management Instructions" when managing a supply shortfall event.

5.3 Returning to normal operation

As the available energy supply permits, the SC must follow the steps identified in Table 1 under the column heading of "Return to Normal Instructions" in reverse order, starting from the last step completed in the adjacent column when managing a supply shortfall event.

5A. Effective Date

The specified amendments cited in Application No 1605243 for Operating Policy and Procedure will be effective 30 calendar days after the date to be determined by the Commission for, collectively, ISO rules consisting of G1 definitions, 6.3.5.1, 6.3.5.2, 6.3.6.2, 6.3.6.3 and Appendix 7 (collectively the "**LLTD Rule**")

6. Figures and Tables

Table 1

Supply Shortfall Management

Step		Supply Shortfall Management Instructions		Return to Normal Instructions
1.	↓	When the short term adequacy program issues an alarm the SC must perform a short term adequacy assessment in accordance with OPP 705.	↑	Take no action in this step.
2.	↓	Perform the planning steps as identified in Section 5.1 when anticipating a supply shortfall.	↑	If planning steps were performed, but the step in this table was not reached that required this action be taken, then undo the planning action that was taken by performing any of the following as required: • Permit transmission maintenance. • Cancel public appeal via Operations on-call person. • Restore DOS 1 hour loads. • Repost export ATC to normal levels. • Notify VRC, BCTC and SPC that an Energy Emergency Alert 1 was not reached. • Dispatch on VLCP loads.
3.	↓	Use all the resources in the energy market merit order to maintain the balance between supply and demand and dispatch assets offered into the ancillary service merit order to provide the required amount of operating reserve. Dispatch off Dispatch Down Service (DDS) with respect to directed long lead time energy (LLTE).	↑	Resume normal energy market dispatch. Dispatch on DDS with respect to directed LLTE.

Step		Supply Shortfall Management Instructions		Return to Normal Instructions
4.	↓	When all resources in the energy market merit order have been dispatched notify the AESO personnel in accordance with Table 1 in OPP 1303 (confidential) and issue the following message in ADAMS to all participants and enter it into the SC Shift Log and select the post to web option "A supply shortfall has commenced. Please confirm must offer volumes of available capability are accurate." Put a comment in the Shift Log in the Additional Information field (to prevent the comment from being posted to the web), stating a request was issued to confirm must offer volumes of available capability are accurate.	↑	Notify the AESO personnel that were previously notified that the supply shortfall event has ended and issue the following message in ADAMS to all participants and enter it into the SC Shift Log and select the post to web option: "The supply shortfall event is no longer in effect and normal operation has resumed."
5.	↓	Maximize the posted import ATC limit by confirming it is based on the lesser of: a. The import limit specified in OPP 304. b. The total amount of Load Shed Service (LSS) currently available. Refer to Table 1 in OPP 312. Notify BCTC if the posted import ATC limit is changed.	↑	Take no action in this step.
6.	↓	Reduce export ATC to zero on the interconnections with BC and Saskatchewan. If possible, re-post the export ATC 1 hour in advance.	↑	Post BCTC and SaskPower import and export ATC to normal levels.
7.	↓	Curtail 1-hour demand opportunity service (DOS) loads. These loads will take up to 1 hour to curtail. Use the list in the DOS program and follow procedures in OPP 901.	↑	Restore DOS 1-hour loads. Use the list in the DOS program and follow procedures in OPP 901.
8.	↓	Curtail 7-minute DOS loads. Use the list in the DOS program and follow procedures in OPP 901.	↑	Restore DOS 7-minute loads. Use the list in the DOS program and follow procedures in OPP 901.
9.	↓	Curtail DOS standard loads. Use the list in the DOS program and follow procedures in OPP 901.	↑	Restore DOS standard loads. Use the list in the DOS program and follow procedures in OPP 901.
10.	↓	Cancel transmission maintenance as necessary to remove generation constraints or increase import ATC on the Alberta-BC and/or Alberta-Saskatchewan interconnection(s) by issuing directives to TFOs and request BCTC and/or SPC to cancel transmission maintenance on their respective systems that reduce import ATC to Alberta.	↑	Permit transmission maintenance to continue that was previously cancelled to remove generation constraints or increase import ATC.

Step		Supply Shortfall Management Instructions		Return to Normal Instructions
11.	↓	If there are non-dispatched external reserves (ER) on the BC interconnection, then maximize the use of external reserves in accordance with the following formula: ER ≤ CRO – Net Imports from BC + Armed ILRAS + LSS where: • ER is the dispatched amount (MW) of external reserves. • CRO is the contingency reserve obligation for the purpose of NWPP reserve sharing group (refer to OPP 405). • LSS is the total of the contracted LSS loads that are on-line. • Armed ILRAS is the amount (MW) of load armed for ILRAS as per OPP 312 if planning step 4 in Section 5.1 was performed to arm ILRAS, otherwise use 0 MW.	↑	Dispatch to the normal level of external supplemental and external spinning reserves, refer to OPP 403.
12.	↓	If the duration of the supply shortfall is expected to be less than 1 hour, then issue directives for dispatched contingency reserves that are in excess of the contingency reserve requirement.	↑	Cancel directives issued for contingency reserves and return to normal dispatch priorities in the ancillary service merit order.
13.	↓	If the duration of the supply shortfall is expected to be less than 1 hour, then dispatch up supplemental loads with standby supply that is offered in the ancillary service merit order and repeat step 12 if dispatches are made.	↑	Take no action in this step.

Step		Supply Shortfall Management Instructions		Return to Normal Instructions
14.	↓	Issue directives for out of market LLTE from generators that were previously directed to start. Perform steps a to d below when all available out of market LLTE has been directed or step b to d below if no LLTE was directed a. Make a note in the Shift Log identifying the time and amount of out of market LLTE that was directed, but do not post it to the WEB. b. Request the VRC to declare an Energy Emergency Alert 1 for the AIES. c. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 1 and make the required notifications. d. Request the AESO operations person on call to notify Stakeholder Relations and Communications in accordance with Table 1 in OPP 1303 (confidential).	↑	If the STA assessment requires the LLTE to be on-line again, direct the assets to their minimum stable load level; otherwise perform the following: a. Cancel directives for out of market LLTE. If minimum run times have not been met then these generators will reduce their output to their minimum stable load level until their minimum run time has been achieved and then they will go off line. b. Make a note in the shift log identifying the time when directives are cancelled for LLTE, but do not post it to the WEB. c. When all directives for LLTE have been cancelled issue the following message in ADAMS to all participants: "Directives have been cancelled for out of market long lead time energy." d. Request the VRC to downgrade the alert for the AIES to an Energy Emergency Alert 0. e. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 0 and make the required notifications.
15.	↓	Take no action in this step. **Note**: If planning step 4 in Section 5.1 was performed to arm ILRAS, then this is the step that was anticipated to be reached to require the use of ILRAS to increase import ATC on the AB-BC interconnection.	↑	Cancel dispatch for arming ILRAS and provide the time when the ILRAS loads are to be disarmed. Determine and post the AB-BC import ATC with only available LSS and put a 0 MW override on the ILRAS value on display #6975
16.	↓	Consider a public appeal if conditions warrant it (step 5 of Section 5.1).	↑	If a public appeal was made, then request the AESO operations on-call person to terminate the public appeal to reduce energy demand.
17.	↓	Request the wire service providers (WSPs) identified in Table 2 (confidential) to institute a 3% distribution voltage reduction.	↑	Notify the WSPs identified in Table 2 (confidential) that the 3% reduction in distribution voltage is no longer required.

Step		Supply Shortfall Management Instructions		Return to Normal Instructions
18.	↓	Call the plant operators for the generators listed in Table 3 (confidential) in sequential order, to give permission to supply additional MWs up to the gross MW level identified in Table 3. If the SC assesses that system conditions do not permit the use of MWs above MAM from an asset, then the SC will skip the asset and go to the next asset in the list. Use the following script: "This is "*your name*", System Controller from the Alberta Electric System Operator. The AIES is in a supply shortfall and "*name & number of generator*" is permitted to supply additional energy up to a gross output level of "*XXX MWs*". Supply of this additional energy is at your discretion, and does not require an energy market restatement or an energy market dispatch."	↑	Call the plant operator(s) that were previously permitted to supply additional MWs up to the gross MW level identified in Table 3 (confidential). Make the calls in the reverse order as in Table 3 and use the following script: "This is "your name", System Controller from the Alberta Electric System Operator. T*he AIES is* returning to normal operation. You are no longer permitted to supply additional energy above your energy market dispatch. "Name & number of generator" is required to return to the energy market dispatch level."
19.	↓	Issue ancillary service directives for supplemental and excess spinning reserves, except for external reserves.	↑	Cancel ancillary service directives for supplemental and excess spinning reserves.
20.	↓	If ILRAS load has not been armed for the current hour, then arm additional ILRAS load to increase Alberta-BC import ATC for the current hour, refer to step 4 in Section 5.1. Post the revised AB-BC import ATC.	↑	
21.	↓	If import ATC is available permit mid-hour interchange transactions with interruptible energy and or interruptible transmission service from importers on the BC and Saskatchewan interconnections up to the posted import ATC limit and issue the following message in ADAMS to all participants: "The AESO will accept mid-hour interchange transactions with interruptible energy and or interruptible transmission service from importers up to the import ATC limit. Valid e-tags submitted for import energy that have not been dispatched will be approved by the SC up to the ATC limit."	↑	Terminate interruptible imports on the Alberta-BC and Alberta-Saskatchewan interconnections and issue the following message in ADAMS to all participants: "Interchange transactions with interruptible energy or interruptible transmission service from importers will no longer be accepted." As applicable, put a comment in the shift log in the Additional Information field (to prevent the comment from being posted to the web), stating the interchange transactions with interruptible energy or interruptible transmission service from Importers has been terminated.
22.	↓	Request the plant or generation operator identified in Table 4 (confidential) to reduce non-essential station service loads.	↑	Restore non-essential station service loads as identified in Table 4 (confidential).
23.	↓	Dispatch off the AESO Voluntary Load Curtailment Program (VLCP) loads as identified in Table 5 (confidential). At least 1 hour notice is required. Log this in the shift log, but do not post it on the web.	↑	Dispatch on the AESO VLCP loads as identified in Table 5 (confidential). Log this in the shift log, but do not post it on the web.

Step	Supply Shortfall Management Instructions		Return to Normal Instructions	
24.	↓	If ATC is constrained down because of the lack of LSS and ILRAS load offers, then disregard this constraint and increase the posted Alberta-BC interconnection import ATC up to the limit as if all available LSS and ILRAS loads are in service. Refer to OPP 304 and OPP 312. Notify BCTC if there is a change to the posted import ATC limit. If additional ATC is available, then issue the following message in ADAMS to all participants: "Import ATC on the Alberta-BC interconnection has been increased for the current hour. Valid e-tags submitted for import energy that have not been dispatched will be approved by the SC up to the ATC limit."	↑	Post the Alberta-BC interconnection import ATC to the limit that reflects the available LSS and ILRAS loads.
25.	↓	Issue directives to curtail all remaining LSS loads. Check the telemetered LSS volumes on Ranger display 6975/HIMP and curtail LSS load if the volume is non-zero. Refer to confidential appendix in OPP 312 for LSS contact information.	↑	Cancel load curtailments directives issued to LSS loads.
26.	↓	Dispatch on external supplemental and external spinning reserves with standby supply types that are offered into the ancillary service merit order, to an amount no greater than the difference between the net interchange schedule on the Alberta-BC interconnection and the posted ATC import limit.	↑	Dispatch off external supplemental and excess external spinning reserves with standby supply types.
27.	↓	If external supplemental and spinning reserves were dispatched, then issue an ancillary service directive(s) for external supplemental and excess external spinning reserves to increase the net interchange schedule on the Alberta-BC interconnection to a level not greater than the posted import ATC limit.	↑	Cancel the ancillary service directive for external spinning and external supplemental reserves.
28.	↓	Issue ancillary service directives for spinning reserves. a. Request the VRC to declare an Energy Emergency Alert 2 for the Alberta balancing authority. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 2 and make the required notifications.	↑	Cancel the ancillary service directive for spinning reserves. a. Request the VRC to downgrade the alert for the AIES to an Energy Emergency Alert 1. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 1 and make the required notifications.
29.	↓	If there is available capacity (i.e., surplus ATC) on the interconnections, request emergency energy from BCTC and SaskPower. Follow the procedures in OPP 803 and OPP 807.	↑	Terminate emergency energy from SaskPower and BCTC.

Step		Supply Shortfall Management Instructions		Return to Normal Instructions
30.	↓	Issue a firm load directive to curtail load. Refer to OPP 802. a. Request the VRC to declare an Energy Emergency Alert 3 for the Alberta balancing authority. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 3 and make the required notifications. c. If 100 MW or more of firm load was curtailed, complete and submit a NERC Preliminary Disturbance Report within 24 hours.	↑	Restore firm load by following the procedures in OPP 802. a. Request the VRC to downgrade the alert for the AIES to an Energy Emergency Alert 2. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 2 and make the required notifications.

The following tables contain confidential information.

To view the tables, click the link below and then provide the password.

View OPP 801 tables

Table 2

3% Distribution voltage reduction

Confidential – see link above for access

Table 3

Gross MW levels permitted above MAM

Confidential – see link above for access

Table 4

Non-essential station service loads

Confidential – see link above for access

Table 5

Voluntary Load Curtailment Program (VLCP) loads

Confidential – see link above for access

7. Revision History

Issued	Description
2012-08-07	Supersedes 2010-03-03, replaced AIES demand with system load
2010-03-03	Supersedes 2009-02-19
2009-02-19	Supersedes 2008-11-13
2008-11-13	Supersedes 2008-05-30
2007-12-03	Supersedes 2007-03-15
2007-03-15	Approved for interim implementation; supersedes 2007-01-17
2007-01-17	Approved for interim implementation; supersedes 2006-12-15
2006-12-15	Approved for interim implementation; supersedes 2005-07-27
2005-07-27	Supersedes 2005-03-30
2005-03-30	Supersedes 2004-12-22
2004-12-22	Approved for interim implementation 2004-12-21; supersedes 2004-03-03
2004-03-03	Supersedes 2003-07-28
2003-07-28	Revised to ISO Operating Policies and Procedures

802 ENERGY EMERGENCY ALERTS AND FIRM LOAD DIRECTIVES

1. Purpose

To define the policies and procedures to issue energy emergency alerts and firm load directives, and to provide guidelines for all parties involved in their responsibilities upon receiving energy emergency alerts or firm load directives from the system controller (SC)

2. Background

In the event of an energy supply shortfall when there is insufficient energy offered in the energy market to meet energy requirements in Alberta, the SC must quickly and clearly communicate the information to all parties involved. The SC accomplishes this by issuing energy emergency alerts in accordance with this OPP. If the energy supply shortfall condition deteriorates, the SC will maintain regulating reserve by issuing firm load directives to curtail firm load, if required. When the energy supply condition allows, the SC will issue directives to restore the curtailed firm load.

It is critical that all involved parties understand these alerts and directives so that they act in a concerted and coordinated effort to maintain the secure and reliable state of the Alberta Interconnected Electric System (AIES).

3. Policy

- Four levels of energy emergency alerts may be issued in an energy supply shortfall situation in accordance with OPP 801, summarized here as follows:

  An **Energy Emergency Alert 1** will be declared **after** the following steps have been taken:

  – All available resources in the energy market merit order are committed to meet AIES firm load and reserve requirements.

  – Non-firm loads have been curtailed.

  – Procedures have been implemented to optimize the use of resources in the ancillary service merit order.

  An **Energy Emergency Alert 2** will be declared **after** the following steps have been taken:

  – All the steps listed under Energy Emergency Alert 1 have been taken.

  – Load management procedures have been implemented, which may include the voluntary load curtailment program, voltage reduction, public appeal to reduce demand and reduction to non-essential loads.

- Ancillary service directives have been issued to supplementary reserves to increase energy supply and firm load is now relied upon for reserve.
- Emergency energy has been requested of neighbouring Balancing Authorities.
- Ancillary service directives have been issued to spinning reserves.

An **Energy Emergency Alert 3** will be declared **after** the following steps have been taken:

- All the steps listed under Energy Emergency Alert 1 and Energy Emergency Alert 2 have been taken.
- Firm load curtailment has been implemented to maintain the minimum required regulating reserve.

An **Energy Emergency Alert 0** will be issued to terminate previous energy emergency alert(s) when energy supply is sufficient to meet AIL and reserve requirements.

- Energy emergency alerts will be issued to parties listed in Table 1 by the indicated methods, as well as posted on the AESO web page in the AIES event log.
- The required firm load curtailment will be shared by all wire owners (WOs) based on the following:

  WO Firm Load Curtailment=Total Firm Load Curtailment*WO Demand/Total Demand of all Pool Purchasers

4. Responsibilities

4.1 ISO

The ISO must:

- Review and update this OPP as required.
- Periodically review and audit firm load curtailment plans with WOs, wire service providers (WSPs) and transmission facility owners (TFOs).
- Any time Energy Emergency Alert 3 is declared, submit the Energy Emergency Alert 3 Report (EOP-002-AB-2 Appendix 1) to the VRC within two business days of the incident.

4.2 System Controller

The SC is responsible for:

- Issuing energy emergency alerts to parties listed in Table 1 by the indicated methods.
- Posting energy emergency alerts on the ISO web page.
- Issuing firm load directives to curtail or restore firm load to parties listed in Table 2.
- Updating the Vancouver Reliability Coordinator (VRC) of the situation until both an **Energy Emergency** Alert 2 and an **Energy Emergency** Alert 3 are terminated.

4.3 Other Market Participants and Transmission Facility Owners (TFOs)

The TFOs will:

- Carry out responsibilities for all emergency alerts listed in Table 1.

4.4 WSPs and WOs

The WSPs and WOs will:

- Develop and maintain load curtailment plans in consultation with TFOs and the ISO in accordance with ISO rule 6.8.
- Comply with SC directives on load curtailments.
- Ensure that load curtailment plans can be implemented at all times.
- Carry out responsibilities listed in Table 1 and Table 2.

5. System Controller Procedures

5.1 Issuing an energy emergency alert

The SC will:

1. Determine if criteria are met for any of Energy Emergency Alert 1, Alert 2, Alert 3 or Alert 0 as described in OPP 801.
2. Request the VRC to declare the alert determined in step 1.
3. If the VRC agrees to the request, then:
    a. Notify the ISO's Operations on-call person.
    b. Issue an Energy Emergency Alert to all market participants with non-zero block(s) in the energy merit order via ADAMS:
        i. Click the message box (telephone) icon on the EMO toolbar.
        ii. Select Alert from the message type drop down list.
        iii. Select the Energy Emergency Alert message from the canned message drop down list.
        iv. Click Send.
    c. Call the TFOs, WSPs and WOs listed in Table 1 to inform them of the Energy Emergency Alert. If a party is listed in more than one category, call that party once only.
    d. Enter the energy emergency alert in the shift log by selecting the appropriate energy emergency alert message from the drop down list and post it to the ISO's web.
4. Update the VRC of the situation at a minimum of every hour until the Energy Emergency Alert 2 or Alert 3, as the case may be, is terminated.

5.2 Issuing a firm load directive to curtail firm load

1. Determine if firm load curtailment is required to maintain the minimum amount of regulating reserve.

2. Calculate each WO's portion of the firm load curtailment using the Load Curtailment Calculator, a Microsoft Excel worksheet residing in the SC_workbook.xls.

   a. Open the "Load shed" worksheet and enter the load amount that is required to be curtailed.

      The worksheet will calculate each WO's portion of load curtailment rounded up to the nearest MW.

   b. Click "Save snapshot of this file" button on the worksheet to save the current calculation as a read-only document for audit purposes.

   c. Print a copy of the worksheet.

3. Issue firm load directives to curtail firm load to the WSPs and WOs listed in Table 2, using the following script:

   a. "This is "your name" with the AESO directing "WSP" to drop XX MWs of firm load by (present time plus 10 minutes). Please repeat this back to me and be sure to notify me when the curtailment is complete."

4. Notify the operation on-call person.

5. Enter the firm load directive in the shift log by selecting the appropriate message from the drop down list and adding to the end of the message the amount of load curtailed. **Do not** post this information to the web.

5.3 Issuing a firm load directive to restore load

The SC will:

1. Determine if enough supply is available to restore all or part of the shed load while maintaining regulating reserves.

2. Determine, if only part of the shed load can be restored, the amount of load restoration for each WO on a pro rata basis.

3. Issue a firm load directive to restore firm load to a new level to each of the WSPs and WOs that has curtailed load, or cancel the firm load directive, using the following script:

   a. "This is "your name" with the AESO directing *WSP*" to a new level of curtailment. Please restore XX MWs of load to a new curtailment level of XX MWs. Please notify me when this new level has been reached."

   b. OR to increase the curtailment level, use the following script.

      "This is "your name" with the AESO directing "WSP" to drop a further XX MWs of firm load to a total curtailed amount of "previous plus new directive level" by (present time plus 10 minutes). Please repeat this back to me and be sure to notify me when the curtailment is complete."

   b. OR for canceling a directive, use the following script.

      "This is "your name" with the AESO canceling the firm load directive issued to "WSP" at (present time)."

4. Enter the firm load directive cancellation in the shift log by closing out the initial directive, or enter a new directive to the new level by starting a new directive and closing out the old one. **Do not** post this information to the web.

5.4 Reporting requirements

In addition to the reporting listed in Section 5.3, the SC will record in the shift log, but **not** post on the web:

a. The cause(s) of the event.

b. The date, time and reason, if known, for any non-compliance of a firm load directive.

6. Figures and Tables

Table 1

Notification list for all energy emergency alerts, and responsibilities of notified parties

Party to be Notified	Notification Method	Responsibilities of Notified Party
All market participants with non-zero blocks bids or offers in the energy market merit order	ADAMS messages	Participants with dispatch rights to generating assets in Alberta must make reasonable efforts to ensure that their generating plant operators are aware of the alerts and that the operators understand that they must contact the SC if there is any work that increases the risk of tripping the generator. The SC will assess the risk and decide if the work should continue or stop.
Transmission Facility Owners (TFOs): • AltaLink Control Center* • ATCO Electric System Control Center * • ENMAX Control Center* • EPCOR Control Center* • Red Deer Electric Control Center* • Lethbridge Electric Control Center * • Medicine Hat Electric Control Center	Phone calls	If there is any work that increases the risk of constraining generation or tripping an interconnection tie line, contact the SC to review and decide if work should continue or stop.
Wire Service Provider (WSP) and Wire Owners (WOs) that are responsible for implementing firm load curtailment procedures: AltaLink Control Center (WSP for FortisAlberta) * • ATCO Electric System Control Center* • ENMAX Control Center* • EPCOR Control Center* • Red Deer Electric Control Center* • Lethbridge Electric Control Center* • Fort Nelson (BC Hydro NCC Distribution Desk Dispatcher)	Phone calls	Review internal firm load curtailment procedure if necessary. If the SC subsequently issues a firm load directive to curtail firm load, the WSPs and WOs must curtail the requested amount of firm load within 10 minutes. If a WSP is to implement firm load curtailment procedures on behalf of a WO, the WSP is responsible to inform the WO of the energy emergency alerts. The SC will not make a separate call to the WO(s) that the WSP represents.

Note:

* This party belongs to both the TFO and WSP/WO categories. The SC will make only one notification to this party for each energy emergency alert. The party must fulfill its responsibilities listed under both categories.

Table 2

Parties to be issued firm load directives and their responsibilities

Parties	Communication Method	Responsibilities of Parties
Wire Service Provider (WSP) and Wire Owners (WOs) that are responsible for implementing firm load curtailment procedures: • AltaLink Control Center (WSP for FortisAlberta) • ATCO Electric System Control Center • ENMAX Control Center • EPCOR Control Center • Red Deer Electric Control Center • Lethbridge Electric Control Center • Fort Nelson (BC Hydro NCC Distribution Desk Dispatcher)	Phone calls	For a firm load directive to curtail firm load: • Curtail the requested amount of firm load within 10 minutes and notify the SC when it is completed. For a firm load directive to restore firm load: • Restore the amount of firm load as directed by the SC and notify the SC when it is completed.

7. Revision History

Issued	Description
2009-09-01	2009-02-19
2009-02-19	Supersedes 2006-11-13
2006-07-11	Supersedes 2003-07-28
2003-07-28	Revised to ISO Operating Policies and Procedures

1304 SYSTEM EVENT MONITORING AND DISTURBANCE REPORTING

1. Purpose

To establish processes for reporting AIES system disturbances and documenting potential recommendations for subsequent action. This OPP outlines criteria for Alberta system relevant events, responsibilities, general content of an Alberta disturbance report, and identification, tracking and resolution of system disturbance issues.

2. Background

Disturbance analysis and reporting is a key process of the reliable and safe operation of power systems. This process is aimed at improving system performance by reviewing system events, and identifying and correcting problems that arise from these events, in a timely and effective manner, thereby minimizing the likelihood of similar events in the future. Also, it will provide valuable feedback to facility owners, system and operations planners and real time operators. An important aspect of this process is disturbance analysis, which plays a critical role in system performance assessment and validation and enhancement of simulation models. System disturbance reports document relevant system events, facility and operational performance analysis results, and issues that require further action.

Prompt notification of system events is critical to ensure timely review and to determine if further investigation is warranted. Avenues to communicate system disturbances must be maintained between real time operations and the persons responsible for equipment and system performance of both the facility operators/owners and the ISO. Monitoring and enforcement processes are employed to ensure that the identified action items are addressed in a timely manner.

3. Policy

3.1 General

Following a system event as defined in Section 3.2, the ISO will complete a prompt review. If deemed to be a reportable disturbance, an investigation will be initiated and, if necessary, a disturbance report completed. The decision to initiate an investigation and to prepare a disturbance report will be made by the ISO (with input from affected parties) and communicated to key parties identified. The ISO will also coordinate the efforts to prepare the disturbance report. The report or parts of it may be submitted to NERC/WECC if required. The disturbance report will not be made public; the dissemination of sensitive information will be done with due regard for the interests of facility owners and facility operators.

E-mail is the preferred communication channel. It may be used for tracking or as reference for closure of issues. A generic e-mail address (opsevents@aeso.ca) will be used for these submissions until ISO personnel have been assigned responsibilities to coordinate this process.

Generally, the disturbance reporting process should be carried out under the rules stated in this OPP. However, there may be situations, such as very large events involving many parties, which will require deviations from these rules. These will be dealt with on a case-by-case basis, based on specific request(s) to the ISO, and agreed upon during the initial assessment (within 24 hours of the event).

3.2 System Events Requiring Further Assessment

The events that require a prompt review and assessment for potential investigation and, if necessary, reporting include but are not limited to the following:

- 300 MW load or more has tripped off for greater than 15 minutes due to an event on the transmission system
- Firm load shedding (manual or automatic) greater than 100 MW or beyond the ISO's current operating criteria in order to maintain security and reliability of the AIES excluding times of energy shortfalls as outlined in OPP 801
- Large geographical areas (two or more facility owners or facility operators) are affected by the same event
- Unplanned tripping of multiple generators
- Events triggering UVLS scheme
- Frequency excursions greater than ±0.05 Hz when AIES remains connected to the WECC system
- Frequency excursions greater than ±0.5 Hz when AIES islands from the WECC system
- Events triggering UFLS scheme
- Multiple transmission system facilities are forced out of service
- Initial indication of protection misoperation (including RAS), cascading outages, incorrect operation of equipment or equipment failure, which impact the transmission system
- Continued operation outside operating criteria (OPPs, ISO Rules)
- Identification of a disturbance beyond recognized criteria
- Any indication of physical or cyber sabotage
- Any unusual event, as deemed by the ISO, or for any event potentially leading to identification of valuable lessons

4. Responsibilities

Investigating and reporting system events are collaborative processes in which affected parties will share responsibilities as described in the following sections.

4.1 ISO

- The ISO is responsible for coordinating the collaborative efforts to assess system events, and, where necessary, investigating and analyzing the event and compiling the disturbance report. Also, the ISO will log, monitor, follow-up, and enforce the action items resulting from this process to ensure timely and effective completion. In this respect, the ISO will:
- Prepare and submit the reports required by the WECC and NWPP (Northwest Power Pool). Also refer to OPP 1305.

- Assess system events and decide whether a disturbance is to be further investigated and reported (a reportable disturbance) based on preliminary information submitted by the facility operator.
- If a disturbance is to be further investigated, identify the key parties to be involved in this process.
- Specify the scope of the review and communicate it to the entities involved in the disturbance.
- Prepare a disturbance report following the investigation of a reportable disturbance within 60 days of the event. Disturbance reports should be shared with the Transmission Operations Coordination Committee (TOCC) affected members and other stakeholders identified during the course of the investigation, for review and comment before finalization. The disturbance report will, in its Recommendations section, identify the issues revealed by the disturbance analysis and specify action items to prevent recurrence of this type of event. Each action item will have a target completion date and identified party responsible for action item resolution.
- If necessary, request information from other parties, including but not limited to ancillary service providers, transmission customers and neighbouring control areas, required to complete the analysis of the disturbance.
- Review the information submissions upon receipt, and notify the sender whether the submission is acceptable.
- Log the issues and the action items identified within the disturbance reports in the ISO maintained disturbance database. The database entry will also identify personnel/party accountable and timelines for the respective issue resolution. The ISO will maintain this contact information up-to-date, based on facility owners' input.
- Track the issues identified within the disturbance report and periodically (no longer than 3 months span) review their status, and provide updates at the TOCC meetings.
- Close the issues identified within the disturbance report based on documentation submitted by the responsible party.
- If necessary, make recommendations for initiation of compliance review, for issues that are not satisfactorily addressed in accordance with agreed upon timelines, or if at any time it is considered that any of the outstanding issues resulting from a disturbance puts system reliability at risk.

System Controller (SC)

- The SC's responsibilities are described in OPP 1305.

4.2 Facility Owners and Facility Operators

This section refers to generation, transmission, and distribution facility owners and operators. The facility owner or facility operator, as appropriate, will:

- Notify the ISO as soon as possible about the occurrence of an event described in Section 3.2 associated with their facilities.
- Upon the ISO's request, submit a preliminary report, as soon as possible but no later than 24 hours after the system disturbance. This report should include, to the extent possible,

the information described in Appendix A or otherwise requested by the ISO. Appendix A also contains a template that may be used for this purpose. A copy of this submission will be sent electronically to opsevents@aeso.ca.

- Submit to the ISO any additional information obtained after the preliminary disturbance report has been submitted.
- Provide the ISO with data records pertaining to a system disturbance under investigation within 5 days of the event and according to the ISO's request specifications.
- Provide the ISO with a full disturbance report within 30 days of any system disturbance deemed reportable by the ISO, describing the root cause of the disturbance, sequence of events, actions taken, any potential issues already identified and suggested course of action. Minimum content and information requirements for the disturbance report are presented in detail in Appendix B. This report is to be e-mailed to opsevents@aeso.ca.
- Inform the ISO about any issues pertaining to the system performance and reliability (for example, changes in protection settings or remedial action schemes, any equipment modification resulting in a change of specifications) as they become aware of them and the course of action they have taken or plan to take to resolve each issue.
- Upon becoming aware of a failure of a Disturbance Monitoring Equipment (DME) or non-compliance with the current standards, immediately advise the ISO and take the necessary action to correct this. DME include phasor measurement units, digital fault recorders, power swing monitors and other sequence-of-events recorders.
- Take immediate action to resolve the outstanding issues presented in the report recommendations (action items with timelines) or as directed by the ISO.
- Provide regular progress reports to the ISO about system disturbance issues (no more than 3 months between reports).
- Provide documentation to the ISO (for example, report of investigation's findings and modifications made to equipment or processes) to support closure of issues identified in the disturbance report.
- Provide the ISO with updated contact personnel information for the disturbance database, if necessary.

Appendix A: AIES Preliminary Disturbance Report Information Requirements

Provide the following information in preliminary disturbance reports within 24 hours of the event:

- Date and time of the disturbance.
- Weather conditions in the area, if relevant for the particular event.
- Brief description of system status before the disturbance, indicating any major elements that were out of service.
- Brief description of the disturbance event, including a list of the elements that tripped, the order in which they tripped, the time each element tripped, and the time each element was restored to service.
- For transmission outages, indicate the amount of load or generation lost as a result of the outage, and the duration of the outage. Provide the time when customer load or transmission access availability for generation was restored.
- For generation outages, indicate the amount of generation lost, the duration of the outage, and the time when the generation was restored. For outages involving multiple generation units, provide the outage duration and restoration time for each unit.
- Indicate the amount of customer load or generation lost due to the operation of under frequency load shed or other remedial action schemes, and indicate the magnitude of load or generation loss for each scheme that operated.
- Provide information on frequency and voltage deviations. (The ISO will use SCADA data available on the PI or PMU database whenever possible).

A preliminary disturbance report template is provided on the next page.

Preliminary Disturbance Report Template

Organization: [Insert here organization name]

Contact Info: [Insert here the contact person info]

Did the event originate in your system? ☐ Yes ☐ No

Cause of Event:

☐ Defective Equipment ☐ Adverse Environment ☐ Human Element
☐ Adverse Weather ☐ System Condition ☐ Foreign Interference
☐ Unknown at this time ☐ Other (Please provide details)

System Status before Event:
[Insert details here]

Sequence of Events:

SCADA Timestamp	Event	Comment
[Event 1 timestamp]	[Event, including protections operations]	[Insert here interpretation, additional details]

Event Details:

Gen tripped (MW) [Insert units here]	[Total in MW] [Unit 1 in MW]		
Load tripped (MW)	Total [Total in MW]	Firm [Firm in MW]	Interruptible [DOS in MW]
Frequency excursions	[Insert details here]		
Voltage excursions	[Insert details here]		
Protections operation	[Insert details here. If UFLS, UVLS, or LSS were triggered, please provide details, i.e. amount of load tripped, location, and timing]		

Restoration Timeline

Element	Outage	Start Restoration	End Restoration
[Element 1]	[Time of the outage]	[Start restoration time]	[End restoration time]

Issues currently under investigation:

[Insert details here]

Appendix B: AIES Disturbance Report

Contents

The system disturbance report will, as a minimum, contain the following sections:

Overview	A summary of the system disturbance, including the amount of load or supply lost.
Sequence of events	Detailed chronological list of applicable system events that occurred during the disturbance.
Conclusions and Recommendations	Conclusions are drawn based on the events comprising the disturbance. A list of issues requiring action is included, and any recommendations, action items and initiatives to prevent recurrence of this type of event. All issues will have a target completion date. A status update will be included for any issues or recommendations that have been addressed before the final draft.
Appendices	May include copies of the facility owners' disturbance reports, data or other relevant information.

The disturbance report will be largely based on the information contained in the facility owner report submitted to the ISO.

Information Requirements

Disturbance reports submitted to the ISO by facility owners or operators must contain the following information:

1. Primary cause of the event – assigned to one of the following standard categories:
   - defective equipment
   - adverse weather
   - adverse environment
   - system condition
   - human element
   - foreign interference
   - unknown
2. Sequence of events with interpretation.
3. Date and time when the event happened and how long it lasted (until all the customers were restored; this includes UFLS, UVLS, etc.).
4. MW lost, in each of the following categories:
   - Load (both DOS and DTS): this should also include the number of customers affected and how long they were without service if this information is available.
   - RAS, SPS
   - Generation: this should include information about unit performance during the disturbance
5. Frequency Excursions: frequency plot, from t-0 until the frequency reached steady-state.

6. Under-Frequency Load Shed (UFLS): details of operation, including what blocks were shed and the MW per block.
7. Voltage Excursions: voltage plots, from t-0 until the voltage reached steady-state.
8. Protection Schemes (including RASs): operation with respect to design.
9. Details of any equipment malfunction that contributed to the disturbance, or equipment damage resulting from the disturbance.
10. SCADA information.

It is recommended that, to the extent possible, the disturbance data be reported in a format capable of being viewed, read and analyzed with a generic COMTRADE (IEEE C37.111-1999 Standard Common Format for Transient Data Exchange for Power Systems) analysis tool, and that the data files be named in conformance with the IEEE C37.232-2007 Recommended Practice for Naming Time Sequence Data Files.

Remediation

If issues have already been identified and an action plan to address them devised or even implemented, the report should also contain:

1. The issues already identified.
2. Remediation plans with specification of the issues addressed.
3. Completion date.
4. Any remediation already completed, with details.

5. Revisions and Approval

Issued	Description
2007-12-03	Supersedes 2003-07-28
2003-07-28	Revised to ISO Operating Policies and Procedures

1305 WECC RELIABILITY MANAGEMENT AND RELATED REPORTING

1. Purpose

This OPP describes Alberta's obligations under the Western Electricity Coordinating Council (WECC) Reliability Management System (RMS) with respect to reporting criteria, monitoring, and compliance with RMS Phase 1, Phase 2 and Phase 3 performance indices.

Related requirements for reporting Path 1 are also included.

2. Background

The purpose of the RMS is to establish reliability standards that participating transmission operators and generators will agree to meet. The objectives of the RMS are to:

- maintain reliability in the interconnected system
- maintain and apply a uniform set of operating criteria
- provide a means to enforce these criteria

Phase 1 of RMS was implemented within the WECC on September 1, 1999. It required control areas to report on Disturbance Control Standard (DCS), Control Performance Standard 1 and 2 (CPS 1 and 2), Operating Transfer Capability (OTC), Operating Reserve Violations, and Generator Power System Stabilizer/Automatic Voltage Regulator (PSS/AVR) performance.

Phase 2 of the RMS (Amendment 2) consists of reporting Operating Limits Available to System Operators, Certification of Protective Relays Applications and Settings, Certification of Remedial Action Schemes, and Protective Relay and Remedial Action Scheme Misoperations. Phase 2 became effective on November 1, 2000.

Phase 3 of RMS (Amendment 3) addresses Interchange Schedule Tagging, Operator Certification, Qualified Path Unscheduled Flow Relief and Transmission Maintenance. Phase 3 became effective on April 1, 2003.

ESBI Alberta Ltd. (EAL) signed the RMS agreement with the WECC, which is now taken over by the ISO. The RMS agreement was approved by the Alberta Energy and Utilities Board (EUB) on May 26, 2000 and came into effect on July 1, 2000. Amendment 5 was signed by the Board on September 28, 2005.

2.1 RMS reporting requirements

Table 1 summarizes the RMS Compliance Standards and Measures.

Table 2 provides RMS Reliability Criteria and related NERC/WECC Standards. In future, WECC standards will replace the RMS Reliability Criteria.

The WECC RMS forms referred in this OPP are available at http://www.wecc.biz/documents/library/RMS/RMS_Forms_9-05-03.xls

2.2 Path 1 reporting requirements

Path 1 is the Alberta-BC interconnection which consists of the 500 kV line (1201L/5L94) between the Langdon substation (T102S) in Alberta and the Cranbrook substation in BC, plus the 138 kV circuits between BC's Natal substation and Alberta's Coleman (T799S) and Pocaterra (T48S) substations (1L275/786L and 1L274/887L, respectively).

In the interest of improving performance of the AB-BC Inter-tie, the AESO and BCTC agreed that the role of the "Path 1 Operator" of the AB-BC Inter-tie will be assumed by the AESO in September 2007. As the Path 1 Operator, the AESO is responsible for coordinating with BCTC, Alta Link, and Vancouver Reliability Coordinator (VRC) for information pertaining to the operation and reliability of Path 1.

3. Policy

- The AESO must administer and monitor the reporting requirements of the WECC Standards within Alberta and report Path 1 reporting requirements beginning September 1, 2007.
- The NERC/WECC Standards specify sanctions for non-compliance with the criterion in Table 1. The sanctions may range from sending a letter to Executives of the non-compliant WECC member to monetary sanctions based on the level and frequency of non-compliance events as specified in Table 4. Any sanctions levied by WECC against ISO will in turn be levied against non-compliant market participant.

4. Responsibilities

The responsibilities of stakeholders for RMS reporting are described below and summarized in Table 3. It also provides reporting requirements as it applies to Path 1. The reporting forms are available on WECC RMS web site (see link in Section 2.1).

4.1 ISO

The ISO must submit to the WECC office:

- OTC Compliance Notification Form A.4 (b) on or before the tenth day of each calendar quarter for the immediately preceding calendar quarter.
- Forms A.5 (a) for PSS data and A.5 (b) for AVR data on or before the twentieth day of the month following the end of a calendar quarter for the preceding quarter.
- Operating Limits Available to System Operator Form A.6 on or before December 1 for each winter limits, May 1 for each spring limits, July 1 for each summer limits, and November 1 for each fall limits.
- Protective Relay and Remedial Action Scheme Misoperations Form A.9 by no later than 5 business days following the occurrence of misoperation, and by no later than 30 days for relay, RAS removal and repair.
- Operating Reserve Compliance Notification Form A.1 (b) on or before the tenth day of each calendar quarter for the immediately preceding calendar quarter.
- NERC Control Performance Standard Survey on or before the fifth day of each month (Form A.3) for the immediate preceding month.
- Qualified Path Unscheduled Flow Relief with the completed USF Reduction Procedure no later than 5 PM Mountain Time on tenth business day following the WECC USF letter.

The ISO must submit to the North West Power Pool (NWPP):

- Reportable Disturbance Verification Form within 48 hours of the disturbance.

The ISO must retain the above data for at least one year, or longer if the data is undergoing a review.

System Controller (SC)

The SC must submit to the WECC Office:

- Preliminary Disturbance Report within 24 hours that is considered a "reportable event" as outlined in Appendix A.
- Operating Reserve Data Reporting Form A.1 (a) by no later than 5:00 PM Mountain Time on the first business day following the day when an instance of non-compliance occurs.
- OTC Reporting Form A.4 (a) for each instance of non-compliance by no later than 5:00 PM Mountain Time on the 1st business day following the day when an instance of non-compliance occurs.
- Operator certification Form 11(a) or Form A.11 (b) on or before the tenth day of each month for the preceding month.
- Interchange Schedule Tagging Form A.10 on or before the tenth day of each month for reporting violation of NERC/WECC Tagging Requirements.

The ISO must retain the above data for at least one year, or longer if the data is undergoing a review.

4.2 Generation Facility Owner (GFO)

The GFOs must:

- Meet the AVR and PSS compliance standards stated in Table 1.
- Submit the following PSS data and AVR data to the ISO by fifth business day of every month:
  - Number of hours that the unit was on-line.
  - Number of hours that the unit was on-line but the PSS was off-line.
  - Number of hours that the unit was on-line but the AVR was not operating in voltage control mode.

4.3 AltaLink as Path 1 Owner of Alberta's Portion of AB-BC Tie-line

The TFO – AltaLink must:

- certify to WECC by January 15 of each year that it has implemented a Transmission Maintenance and Inspection Plan (TMIP) in compliance with the Transmission Maintenance Standard (Form A.12) for Alberta's portion of AB-BC tie-line.
- submit Certification of Protective Relay Applications and Settings Form A.7 on or before September 15 of each year.
- submit Certification of Remedial Action Schemes Form A.8 on or before September 15 of each year.

AltaLink must take the following actions and the lead for any investigation for each known or probable relay or RAS misoperation in its portion of the AB-BC Interconnection.

- If a functionally equivalent protective relay or a remedial action scheme (RAS) remains in service to ensure bulk transmission system reliability, the relay or RAS that misoperated must be removed from service for repair or modifications within 22 hours of the misoperation. The relay or RAS must be replaced, repaired or modified so that the misoperation will not be repeated.
- If a functionally equivalent protective relay or a RAS does not remain in service to ensure bulk transmission system reliability, and the relay or RAS that misoperated can not be replaced and placed back in service within 22 hours, the associated transmission path facility must be removed from service.
- If a relay or RAS misoperates and there is some protection but it is not entirely functionally equivalent, the relay or RAS must be repaired or removed from service within 22 hours.
- The protective relays or RAS must be removed from service, repaired or replaced with functionally equivalent protective relays or a RAS within 20 business days of removal, or the associated transmission path elements must be removed from service.

AltaLink must retain the data for at least one year, or longer if required to address a question of compliance.

4.4 BCTC as Path 1 Owner of Alberta's Portion of AB-BC Tie-line

The BCTC must:

- certify to WECC by January 15 of each year that it has implemented a TMIP in compliance with the Transmission Maintenance Standard (Form A.12) for BC's portion of AB-BC tie-line.
- submit Certification of Protective Relay Applications and Settings Form A.7 on or before September 15 of each year.
- submit Certification of Remedial Action Schemes Form A.8 on or before September 15 of each year.

BCTC must take the following actions and the lead for any investigation for each known or probable relay or RAS misoperation in its portion of the AB-BC Interconnection:

- If functionally equivalent protective relay or a RAS remains in service to ensure bulk transmission system reliability, the relay or RAS that misoperated must be removed from service for repair or modifications within 22 hours of the misoperation. The relay or RAS must be replaced, repaired or modified so that the misoperation will not be repeated.
- If a functionally equivalent protective relay or a RAS does not remain in service to ensure bulk transmission system reliability, and the relay or RAS that misoperated can not be replaced and placed back in service within 22 hours, the associated transmission path facility must be removed from service. The remaining path facility, if any, must be derated to a reliable operating level.
- If a relay or RAS misoperates and there is some protection but it is not entirely functionally equivalent, the relay or RAS must be repaired or removed from service within 22 hours. The associated transmission may remain in service, but system operation must

fully comply with the WECC and NERC operating standards. This may require an adjustment of operating level.

- The protective relays or RAS must be removed from service, repaired or replaced with functionally equivalent protective relays or RAS within 20 business days of removal, or the system must be operated at levels that meet the WECC and NERC standards, or the associated transmission path elements must be removed from service.

The BCTC must retain the data for at least one year, or longer if required to address a question of compliance.

5. System Controller and Operations On-Call procedures for Path 1

The SC and OOC will use the following procedures for Path 1.

5.1 OTC Limits

The SC will:

1. Determine OTC export and import limits as described in OPP 304.
2. Communicate the limits to VRC and BCTC through ICCP in real time.

5.2 OTC Violation Mitigation

The SC will:

1. Monitor actual flows on Path 1 to ensure they do not exceed the import/export OTC limits for more than 20 minutes.
2. Mitigate any violation of the OTC limits through generation dispatch, curtailment of load and/or inter-tie schedule.

5.3 OTC Violation

In the event the OTC limit is violated, the SC will:

1. Establish communication with the VRC, BCTC, and AltaLink (as time permits) to keep them informed of the OTC violation and the actions being taken to mitigate it.
2. Notify Operations On-Call if the OTC violation continues for more than 20 minutes.
3. Log the details of an OTC violation exceeding 20 minutes in the Shift Log.

5.4 VRC Communication

When contacted by the VRC, after the OTC limits have been exceeded for more than 2 minutes, the SC will:

1. Establish a communication channel, and obtain an update on the reason for the OTC violation and the actions being taken to mitigate it.
2. Obtain a further update when requested by the VRC after the OTC limits have been exceeded for more than 10 minutes, again including the reason for the OTC violation and the actions being taken to mitigate it.
3. Take action to mitigate the OTC violation when so directed by the VRC after the OTC limits have been exceeded for more than 15 minutes.

Note: If OTC limits are exceeded for more than 20 minutes, the AESO will be considered to be in non-compliance and may face sanctions and fines.

5.5 RAS or Relay Misoperation

When there is a disturbance on Path 1, the SC will:

1. Coordinate with BCTC and AltaLink to restore the path.
2. Communicate with BCTC and AltaLink to obtain information about any actual or potential misoperation of a Path 1 relay or RAS.
3. Notify Operations On-call if it is a Path 1 relay or RAS misoperation.
4. Notify Operations On-call if the cause of a Path 1 relay or RAS misoperation is undetermined.
5. Log the details of the relay or RAS misoperation in the Shift Log.

5.6 Preliminary Disturbance Reporting

If there is a disturbance on Path 1, the SC will:

1. Coordinate with BCTC and AltaLink to restore the path.
2. Communicate with BCTC and AltaLink to obtain information about the disturbance.
3. Complete a Preliminary Disturbance Report within 24 hours and submit it on the WECCnet if the Path 1 outage or failure is considered a "reportable event" as outlined in Appendix A.

5.7 OTC Non-Compliance Reporting

If Operations On-Call (OOC) is notified by the SC that an OTC violation exceeded 20 minutes, OOC will:

1. Complete WECC RMS Form A.4 (a).
2. Submit the form to the WECC office by no later than 5:00 PM Mountain Time on the first business day following the day when the instance of non-compliance occurs.

Note: Promptly self reporting the non-compliance may reduce the fines or sanctions considered.

5.8 RAS/Relay Misoperation Communication

If OOC is notified by the SC that a relay or RAS misoperation has occurred on Path 1, OOC will:

1. Notify the Operation Planning & Analysis Manager, regardless of whether the cause of the misoperation is determined
2. Ensure that the relay or RAS that misoperated is removed from service for repair or modification as required by the TFO or BCTC under Section 4.3 or Section 4.4, respectively.
3. Ensure Path 1 is operated at levels that meet WECC standards.

6. Figures and Tables

Table 1

RMS compliance standards and non-compliance measures

	Reliability Criterion	Compliance Standard	Non-compliance Measure
1	Operating Reserves	Must maintain 100% of required Operating Reserve levels based on data averaged over each clock hour. Re-establish the required Operating Reserve within 60 minutes following every event requiring the activation of Operating Reserve.	One instance during a calendar month in which the Operating Reserve is <100%.
2	Disturbance Control Performance	The Area Control Error (ACE) must return to zero within 15 minutes if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the ACE should return to its pre-Disturbance value. The Reportable Disturbances is a disturbance within the NWPP that has caused the ACE for the NWPP to change by 35% of its most severe single contingency or by 260 MW, whichever is less. The Contingency Reserve must be fully restored within 60 minutes. If DCS is not met, the Contingency Reserve for the calendar quarter will be increased in proportion to non-compliance with the DCS in the preceding quarter.	Compliance with the DCS must be measured on a percentage basis. The expected compliance average percent recovery for the quarter is 100%.
3	Control Performance Standard One	CPS1 measures control performance by comparing how well a Control Area's ACE performs in conjunction with the frequency error of the Interconnection.	The acceptable control performance rating is CPS1 $\geq$100%
4	Control Performance Standard Two	CPS2: Average ACE for each 10-minute period must be within the L_{10} limit (L_{10} is the MW bound).	The acceptable control performance Rating is CPS2 $\geq$90%.
5	Operating Transfer Capability	Actual power flow on Path 1 (AB-BC Tie-line) must not exceed the OTC for >20 minutes.	Percentage by which net schedule or actual flows exceed OTC.
6	Operating Limits Available to System Operator	Complete certification that OTC documentation has been completed and distributed.	Certification of OTC limits for the operating seasons.
7	Certification of Protective Relay Applications and Settings	Accurately complete the Protective Relay Application and Settings Certification form A.7 for AB-BC Tie line	Complete the Protective Relay Application and Settings Certification form.
8	Certification of Remedial Action Schemes	Accurately complete the Protective Relay Application and Settings Certification form A.7 for AB-BC Tie line	Complete the Protective Relay Application and Settings Certification form.
9	Protective Relay and Remedial Action Scheme Misoperations	Submit to WECC the completed Protective Relays and Remedial Action Scheme Misoperation Reporting Forms for AB-BC tie-line on time. The relay or RAS that misoperated is to be removed from service for repair or modification within 22 hours of the relay or RAS misoperation. Protective relays or RAS removed from service must be	Removal of Relay or RAS in >22 hours. Repair or replacement of Relay/RAS in >20 business days.

	Reliability Criterion	Compliance Standard	Non-compliance Measure
		repaired or replaced with functionally equivalent protective relays or RAS within 20 Business Days of removal.	
10	Operator Certification	All system operators must be NERC-Certified.	Percent of Non-Certified person-hours are >0%.
11	Qualified Path Unscheduled Flow Relief	Take appropriate actions to relieve transmission loading such as notifying VRC and others to curtail Interchange Transactions and provide documentation as requested by UFAS and/or WECC staff not later than 5 PM Mountain Time following the date of the WECC staff USF letter.	Magnitude of MWh relief required, and the ratio of actual MWh relief provided to the required MWh of relief for every hour that the curtailment requirement was in effect.
12	Transmission Maintenance Standard	Develop, document and implement a Transmission Maintenance and Inspection Plan (TMIP), perform maintenance and maintain maintenance records for AB-BC tie-line (Path 1).	Certification that TFO has developed and documented a TMIP and fulfilling maintenance, testing and inspection.
13	Interchange Schedule Tagging	TP (Transmission Provider) and TAE (Tag Approval Entity)-AESO TAE's approval service has not implemented or fail to implement an availability of >99.5% of the time during a calendar month. TAE did not actively process (approve or deny) at least 75% of the tags received in a month.	WECC's tagging service monitors performance of TAE. The AESO service availability is <99.5%. The AESO actively processed tags are <t75%.
14	Automatic Voltage Regulators (AVR)	Each generating unit equipped with AVR must have the AVR in service when the unit is on line. AVR is to be operated in voltage control mode. The period of operation without AVR should not exceed 60 days. If a decision is made to replace the excitation system, the excitation system including AVR should be back within one year. WECC should be contacted if further extension is required.	AVR is in service <98% of all hours during which generating unit are on line for each calendar quarter. AVR is out of service >7 calendar days due to maintenance in a quarter. AVR is out of service for >60 calendar days due to failed component
15	Power System Stabilizers (PSS)	Each generating unit equipped with and PSS must have the PSS in service when the unit is on line. The period of operation without PSS should not exceed 60 days. If a decision is made to replace the excitation system, the excitation system including PSS should be back within one year. WECC should be contacted if further extension is required.	PSS is in service <98% of all hours during which generating unit are on line for each calendar quarter. PSS is out of service >7 calendar days due to maintenance in a quarter. PSS is out of service for >60 calendar days due to failed component

Table2

RMS reliability criteria and NERC and WECC standards

	Reliability Criterion	NERC Standard	WECC Standard
1	Operating Reserves		BAL-STD-002
2	Disturbance Control Performance	BAL-002	BAL-STD-002 WECC MORC NWPP Reserve Sharing program
3	Control Performance Standard One	BAL-001	
4	Control Performance Standard Two	BAL-001	
5	Operating Transfer Capability		TOP-STD-007
6	Operating Limits Available to System Operator		TOP-STD-007
7	Certification of Protective Relay Applications and Settings		PRC-STD-006
8	Certification of Remedial Action Schemes		PRC-STD-006
9	Protective Relay and Remedial Action Scheme Misoperations		PRC-STD-003
10	Operator Certification	PER-003	
11	Qualified Path Unscheduled Flow Relief		IRO-STD-006
12	Transmission Maintenance Standard		PRC-STD-005
13	Interchange Schedule Tagging	INT-001 INT-002 INT-003	
14	Automatic Voltage Regulators (AVR)		VAR-STD-002a
15	Power System Stabilizers (PSS)		VAR-STD-002b

Table 3

RMS reporting requirements and responsibilities

	Reliability Criterion	Reporting Requirements	Responsibility	Applies to Path 1?
1	Operating Reserves	Form A.1(a) By no later than 5 PM Mountain Time on the first business day following the day on which non-compliance occurs. Form A.1(b) On or before tenth day of each calendar quarter for the immediate preceding calendar quarter.	SC Operations Coordination	No
2	Disturbance Control Performance	Preliminary Reportable Disturbance Form sent to WECC within 24 hours. See Appendix A. Reportable Disturbance Verification Form sent to NWPP within 48 hours. Form A.2 sent to NERC on or before fifth day of each month for the immediate preceding month.	SC Operations Coordination NWPP	No

OPP 1305 WECC Reliability Management and Related Reporting

	Reliability Criterion	Reporting Requirements	Responsibility	Applies to Path 1?
3	Control Performance Standard One	Form A.3 On or before fifth day of each month for the immediate preceding month.	Operations Coordination	No
4	Control Performance Standard Two	Form A.3 On or before fifth day of each month for the immediate preceding month.	Operations Coordination	No
5	Operating Transfer Capability	Form A.4(a) By no later than 5 pm Mountain Time on the first business day following the day on which non-compliance occurs. Form A.4(b) On or before tenth day of each calendar quarter for the immediate preceding calendar quarter.	SC Operations Coordination	Yes
6	Operating Limits Available to System Operator	Form A.6 On or before December 1 for winter season. On or before May 1 for each Spring season. On or before July 1 for each Summer season. On or before November 1 for each Fall season.	Operations, Planning and Analysis	Yes
7	Certification of Protective Relay Applications and Settings	Form A.7 On or before September 15 of each year.	TFOs, BCTC	Yes
8	Certification of Remedial Action Schemes	Form A.8 On or before September 15 of each year.	TFOs, BCTC	Yes
9	Protective Relay and Remedial Action Scheme Misoperations	Form A.9 By no later than 5 business days following the occurrence of relay misoperation. Form A.9 By no later than 30 business days for relay/RAS removal/repair.	Operations, Planning and Analysis Operations, Planning and Analysis	Yes
10	Operator Certification	Form A.11(a) or Form A.11(b) On or before tenth day of each month for the immediate preceding month.	Operations Coordination	No
11	Qualified Path Unscheduled Flow Relief	By no later than 5 Mountain Time on tenth business day following the WECC USF letter, submit the completed USF Reduction Procedure.	Operations Coordination	No
12	Transmission Maintenance Standard	Form A.12 On or before January 15 of each year, certify that it has implemented TMIP program.	TFO,BCTC	Yes
13	Interchange Schedule Tagging	Form A.10 On or before tenth day of each month submit the forms for Reporting Violations of NERC/WECC Tagging Requirements.	SC	No

	Reliability Criterion	Reporting Requirements	Responsibility	Applies to Path 1?
14	Automatic Voltage Regulators (AVR)	Provide information contained in Form A.5 by fifth business day of every month. Form A.5 On or before twentieth day of the month following the end of a quarter for the immediately preceding quarter.	GFOs ISO	No
15	Power System Stabilizers (PSS)	Provide information contained in Form A.5 by fifth business day of every month. Form A.5 On or before twentieth day of the month following the end of a quarter for the immediately preceding quarter.	GFOs ISO	No

Table 4

Sanctions for non-compliance

Non-Compliance Level	Number of Occurrences at a Given Level within Specified Period			
	1	2	3	4 or more
Level 1	Letter (A)[1]	Letter (B)[2]	Higher of $1,000 or $1 per MW of Sanction Measure	Higher of $2,000 or $2 per MW of Sanction Measure
Level 2	Letter (B)	Higher of $1,000 or $1 per MW of Sanction Measure	Higher of $2,000 or $2 per MW of Sanction Measure	Higher of $4,000 or $4 per MW of Sanction Measure
Level 3	Higher of $1,000 or $1 per MW of Sanction Measure	Higher of $2,000 or $2 per MW of Sanction Measure	Higher of $4,000 or $4 per MW of Sanction Measure	Higher of $6,000 or $6 per MW of Sanction Measure
Level 4	Higher of $2,000 or $2 per MW of Sanction Measure	Higher of $4,000 or $4 per MW of Sanction Measure	Higher of $6,000 or $6 per MW of Sanction Measure	Higher of $10,000 or $10 per MW of Sanction Measure

Note:

1. Letter (A) is the Letter to Participant's Chief Executive Officer informing Participant of noncompliance with copies to NERC, WECC Member Representative, and WECC Operating Committee Representative.
2. Letter (B) is identical to Letter (A), with additional copies to (i) Chairman of the Board of Participant (if different from Chief Executive Officer), and to (ii) state or provincial regulatory agencies with jurisdiction over the Participant.

Appendix A. Standard EOP-004-1 — Disturbance Reporting Attachment 1-EOP-004

NERC Disturbance Report Form

Introduction

These disturbance reporting requirements apply to all Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load Serving Entities, and provide a common basis for all NERC disturbance reporting. The entity on whose system a reportable disturbance occurs shall notify NERC and its Regional Reliability Organization of the disturbance using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. Reports can be sent to NERC via email (esisac@nerc.com) by facsimile (609-452-9550) using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. If a disturbance is to be reported to the U.S. Department of Energy also, the responding entity may use the DOE reporting form when reporting to NERC. Note: All Emergency Incident and Disturbance Reports (Schedules 1 and 2) sent to DOE shall be simultaneously sent to NERC, preferably electronically at esisac@nerc.com.

The NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports are to be made for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
   a. Modification of operating procedures.
   b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
   c. Identification of valuable lessons learned.
   d. Identification of non-compliance with NERC standards or policies.
   e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
   f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. The occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
   a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
   b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.
6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:

a. Sustained voltage excursions equal to or greater than ±10%, or

b. Major damage to power system components, or

c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention, which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.

7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.

8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

Adopted by Board of Trustees: November 1, 2006

Effective Date: January 1, 2007

Standard EOP-004-1 — Disturbance Reporting

NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

☐ Check here if this is an Interconnection Reliability Operating Limit (IROL) violation report.

1.	Organization filing report.		
2.	Name of person filing report.		
3.	Telephone number		
4.	Date and time of disturbance Date:(mm/dd/yy) Time/Zone:		
5.	Did the disturbance originate in your system?	☐ Yes ☐ No	
6.	Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence.		
7.	Generation tripped. MW Total List generation tripped		
8.	Frequency. Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):		
9.	List transmission lines tripped (specify voltage level of each line).		
10.	Demand tripped (MW): Number of affected Customers	Firm	Interruptible

Adopted by Board of Trustees: November 1, 2006 Page 8 of 13 Effective Date: January 1, 2007

Note: Please send a copy to WECC at disturbancereports@wecc.biz

7. Revision History

Issued	Description
2008-11-13	Supersedes 2008-08-11
2008-08-11	Supersedes Interim OPP: 2008-01-09
2008-01-09	Supersedes 2007-12-12
2007-12-12	Supersedes 2003-07-28
2003-07-28	Revised to ISO Operating Policies and Procedures

Alberta Electric System Operator
2500, 330 – 5th Avenue SW
Calgary, Alberta T2P 0L4
Phone: 403-539-2450
Fax: 403-539-2949
www.aeso.ca
www.poweringalberta.com

REV 0413

NOTICE TO MARKET PARTICIPANTS AND STAKEHOLDERS

Date: November 2, 2012

Re: July 9 2012, Load Shed Event

This Notice reports on the Market Surveillance Administrator's findings with respect to the load shed event that occurred in parts of Alberta on July 9, 2012.

The MSA's responsibility in a matter of this nature is to review whether any rules, reliability standards or provisions of the *Electric Utilities Act* were violated by market participants or the Alberta Electric System Operator (AESO) leading up to or during the event.

In brief, we find no evidence of wrongdoing by any of the parties, neither regarding compliance with the market rules and reliability standards, nor with respect to allegations of manipulation of the market or collusion among participants. The circumstances that led to the controlled action initiated by the AESO were a combination of peak summer demand for electricity and generator equipment issues caused by high temperatures.

There are always lessons to be learned from critical events such as occurred on July 9, 2012. While the MSA offers some suggestions in this Notice, these are matters squarely under the purview and that engage the professional expertise of the system operator, the AESO.

The body of this Notice summarizes our findings. An Attachment summarizes the conditions before July 9 and provides a chronology of events on the day leading to the controlled load shed and the restoration. Also attached to the Notice is a glossary and brief description of the operation of electric systems and the roles of the relevant agencies: the Alberta Electric System Operator, Market Surveillance Administrator, Alberta Utilities Commission, and the Western Electricity Coordinating Council. The Overview and Glossary in Attachment B is meant to assist those who don't have a close familiarity with the electricity sector; it is by no means comprehensive.

Our Approach

The Market Surveillance Administrator (MSA) is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants and the Alberta Electric System Operator (AESO) comply with the Alberta Reliability Standards and the Independent System Operator Rules (ISO rules).

The MSA reviewed both the conduct of the market participants and the AESO on July 9, 2012 when 200 megawatts (MW) of Alberta load was shed as a result of insufficient generation.

While July 9, 2012 was expected to be a hot day, the AESO forecast that there was sufficient generation and imports to meet the anticipated load. At the beginning of the day the AESO anticipated there would only be one generator out of service on a planned outage and there was sufficient generation to meet both energy and operating reserve requirements. Over the course of the day the available supply to meet the load deteriorated as a result of up to 10 generators being forced from service at various times. By the afternoon, after all supply and operating reserve were exhausted the AESO found it necessary to request 200 MW of load shedding.

The AESO has a legislated mandate to operate the system in the Alberta control area within its design limits and with respect to its Operating Limits and Procedures. During periods of stress such as when there is insufficient generation to meet load, the use of these procedures is critical to ensure the continued safe and reliable operation of the system. Well understood procedures ultimately protect the electrical grid when the operator is facing significant system challenges.

What We Looked At

In the course of our review, we examined confidential generator reports as to what had occurred to force them from service, their actions in restarting their generation to return to service and the generators' review of maintenance and calibration procedures.

We have also reviewed the AESO's operating procedures, the AESO's actions and the various tools available to them to ensure reliability.

What We Found

We are satisfied that the July 9, 2012 event resulted from a confluence of peak summer load and coincidental generator forced outages due to high ambient temperature conditions. We have not uncovered any breaches of the ISO rules, Alberta Reliability Standards or anticompetitive conduct in violation of the *Electric Utilities Act.*

There is no evidence of market manipulation by generators and, to the contrary, in the course of our review we found that generators had made substantial efforts to return to service. We have found no correlation between the design of the electricity market and the load shedding event.

Over the course of July 9, 2012 ten generating units operated by six different market participants and accounting for over 1400 MW of energy were forced from service for periods of time. From our review of the confidential generators' reports we conclude that the coincident loss of so many generators was as a result of many unrelated factors, including:

- Hot weather - up to that point the hottest day of the summer - stressing the units;
- Maintenance / calibration procedures on several generators that appear to have been improperly applied.

We understand that event investigation by the AESO has already led to the submission and approval of a number of corrective action plans by generators to mitigate similar operational issues from arising in the future.

Next Steps / Recommendations

We have asked the AESO to review one of its look ahead short term forecasting tools to determine if the most appropriate inputs are being used. One can consider this tool as an early warning to potential troubles ahead. In our view, this did not contribute to the July 9, 2012 event but a more robust tool might have been able to provide more advanced warning of the potential supply adequacy issues.

Similarly, it is a known phenomenon that the actual output of generators is impeded by ambient temperature conditions and we have suggested to the AESO that a better understanding of the implications may allow modeling this capacity into its tools.

The present ISO rules and Alberta Reliability Standards derived from NERC Reliability Standards do not appear to place an onus on generators to follow their documented maintenance procedures. We recommend that the AESO take the lead with the participants to determine whether to develop some form of accountability for generators to ensure their documented procedures – notably maintenance and calibration - are followed.

The AESO continues to review and assess its internal processes and procedures and will share its findings with MSA in due course. We look forward to further discussion of these issues.

July 9, 2012 was a serious event. The MSA is confident that the AESO and market participants are committed to learn from the experience to be in a better position to respond to similar challenges that may arise in the future.

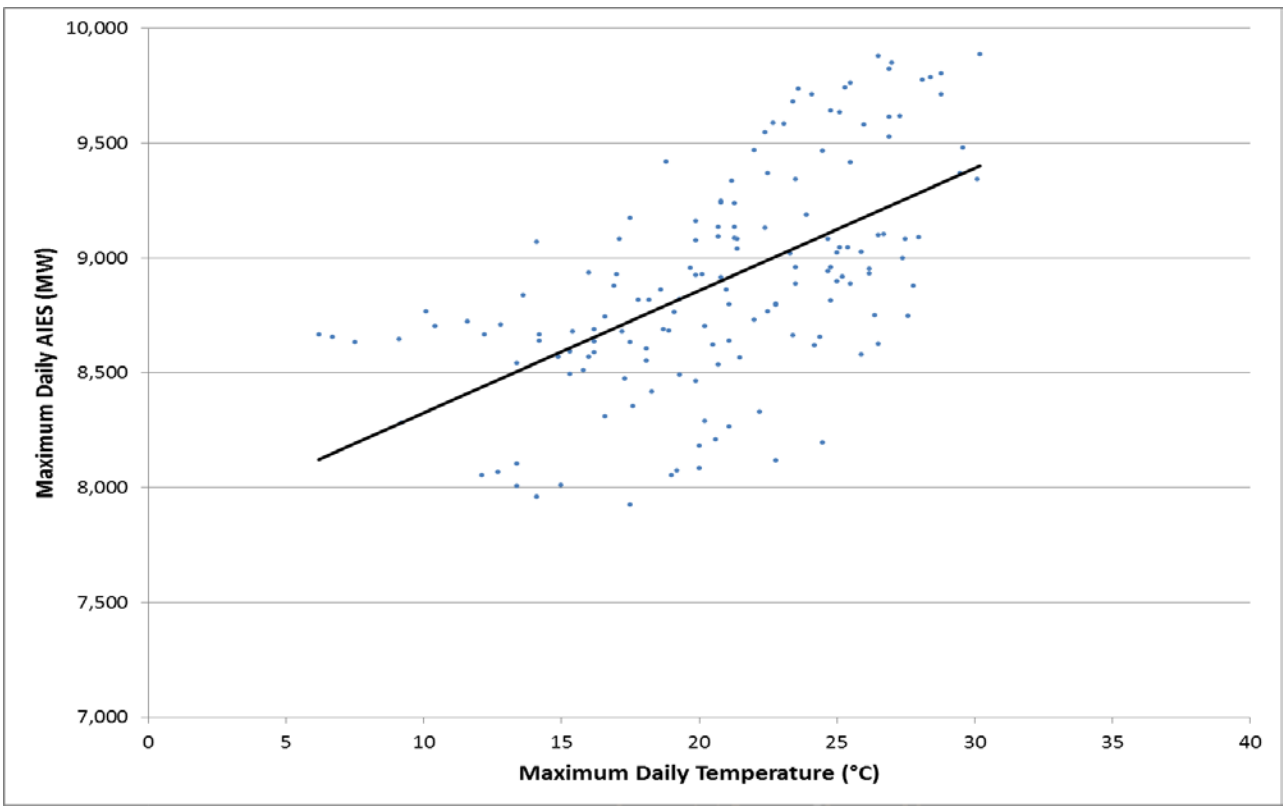
Attachment A - Chronology of Events

July 9, 2012 was a notable day as AESO faced a shortage of available generation and was forced to curtail load for several hours to keep the system secure. The following description focuses on the outlook prior to the day and the events of the day, from a market perspective.

Outlook Prior to July 9

During the week prior to Monday July 9, there were indications that it would be tight day for the market. The weather forecast was for a hot day. This tends to increase the load on the system; a rule of thumb is 50 MW per 1 degree Celsius rise. This is supported by the data of Figure 1 that shows maximum daily loads versus the corresponding daily maximum temperature for May through September, 2012.

Figure 1: Maximum Daily Load and Maximum Daily Temperature



Further to that, Monday is generally the highest load day of the week due to the startup of many businesses that were closed over the weekend. July 8 yielded the highest ever summer peak demand for a Sunday and, with no break in the weather expected, set up Monday July 9 as a very high demand day.

Over the weekend, only one unit was on maintenance and no major outages were scheduled for Monday. However, hot weather causes many thermal units to be derated from their normal maximum capability. Also, hot days frequently produce little wind generation.

Forward trading for Monday July 9 was relatively brisk as companies sought to manage their exposure to pool price. Around 40 MW traded at prices in the range $200 – 225/MWh. Given that most traders would expect the off-peak prices to be quite low, such prices for the whole 24 hours of the day imply an expectation of on-peak prices in the $500 – 800/MWh range. For comparison, at that time, the 30-day rolling average pool price was $36.93/MWh.

Events on July 9

By the morning of July 9 some things became more certain. The expectation was that the temperature would reach 30 degrees Celsius and a record high summer demand was a prospect. In the event, a new record of 9885 MW was set in HE14.

At 7 am the only unit of significant size offline was the one that went on outage over the weekend and its return to service was delayed. There were no strong signals that a generation adequacy issue was in the offing. In fact, AESO's Supply Adequacy report showed more than 400 MW of energy in the merit order above that needed for the load for all hours of the day. Over the next 7 hours or so, however, over 1400 MW of capacity across 10 generating units (operated by six different market participants) was forced out of service for various periods of time, ultimately leading to some shedding of load. A summary is provided in Table 1.

Table 1: Significant Events on July 9, 2012

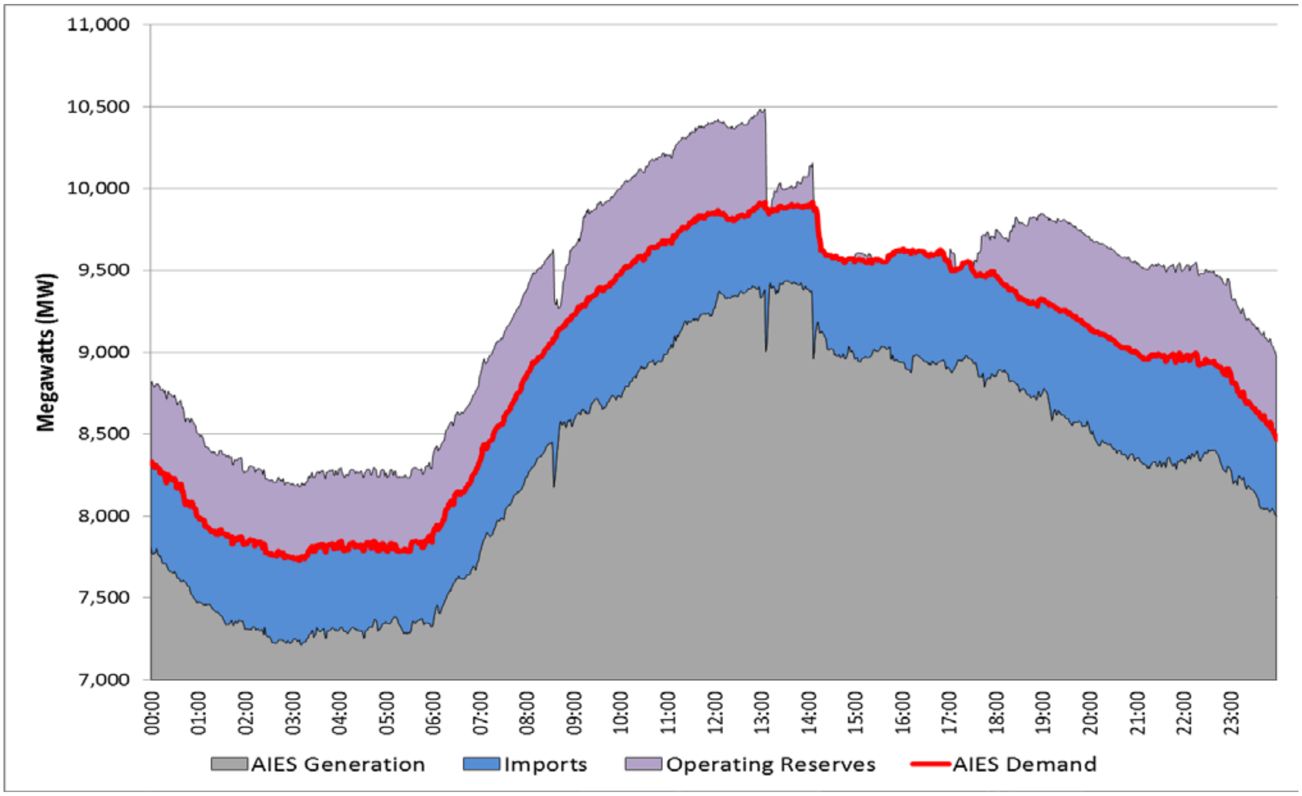
Time	Event	Fuel Type	MW*	Starts Return
08:34	Battle River 5 - forced	Coal	(324)	July 14
12:58	Balzac GS - forced	Gas	(78)	13:35
13:05	Keephills G1 - forced	Coal	(393)	18:16
13:18	Poplar Hill G1 - forced	Gas	(33)	17:34
13:34	EEA1 declared	n/a	n/a	n/a
14:04	AESO asks BC Hydro to cancel transmission outage	n/a		15:48
14:06	Genesee G2 - forced	Coal	(400)	17:12
14:08	EEA2 / EEA3 declared	n/a	n/a	n/a
14:08	Rotating blackout implemented	n/a	200	n/a
14:15	Mahkeses GT91 forced	Gas	(71)	14:45
14:21	Saskatchewan provides emergency energy	n/a	60	n/a
14:58	Sundance #3 – return from planned outage	Coal	362	14:58
15:00	Saskatchewan provides emergency energy	n/a	100	n/a
15:39	Rotating blackout	n/a	100	n/a
15:46	Joffre CT201 - forced	Gas	(205)	17:00
15:48	BC Hydro Transmission outage ended	n/a		n/a
15:48	BC Hydro Import ATC increased from 495 to 575	n/a	80	n/a
17:10	Rotating blackout ended	n/a	n/a	n/a
17:15	Crossfield G2 - forced	Gas	(41)	18:48

*Brackets in this column indicate loss of MW.

Source: AESO, "AIES Event Log"

At 13:34 the AESO declared Energy Emergency Alert 1, meaning that the normal energy merit order was exhausted. Soon after, Emergency Alerts 2 and 3 were declared leading to the curtailment of load of 200 MW at 14:08. The AESO was able to eliminate all load shedding by 17:10 and system normal conditions resumed at 18:48 (Energy Emergency Alert 0) and the system controller returned to dispatching the merit order. A useful diagram to show how the merit order was exhausted and how the reserves were then converted to energy is presented in Figure 2.

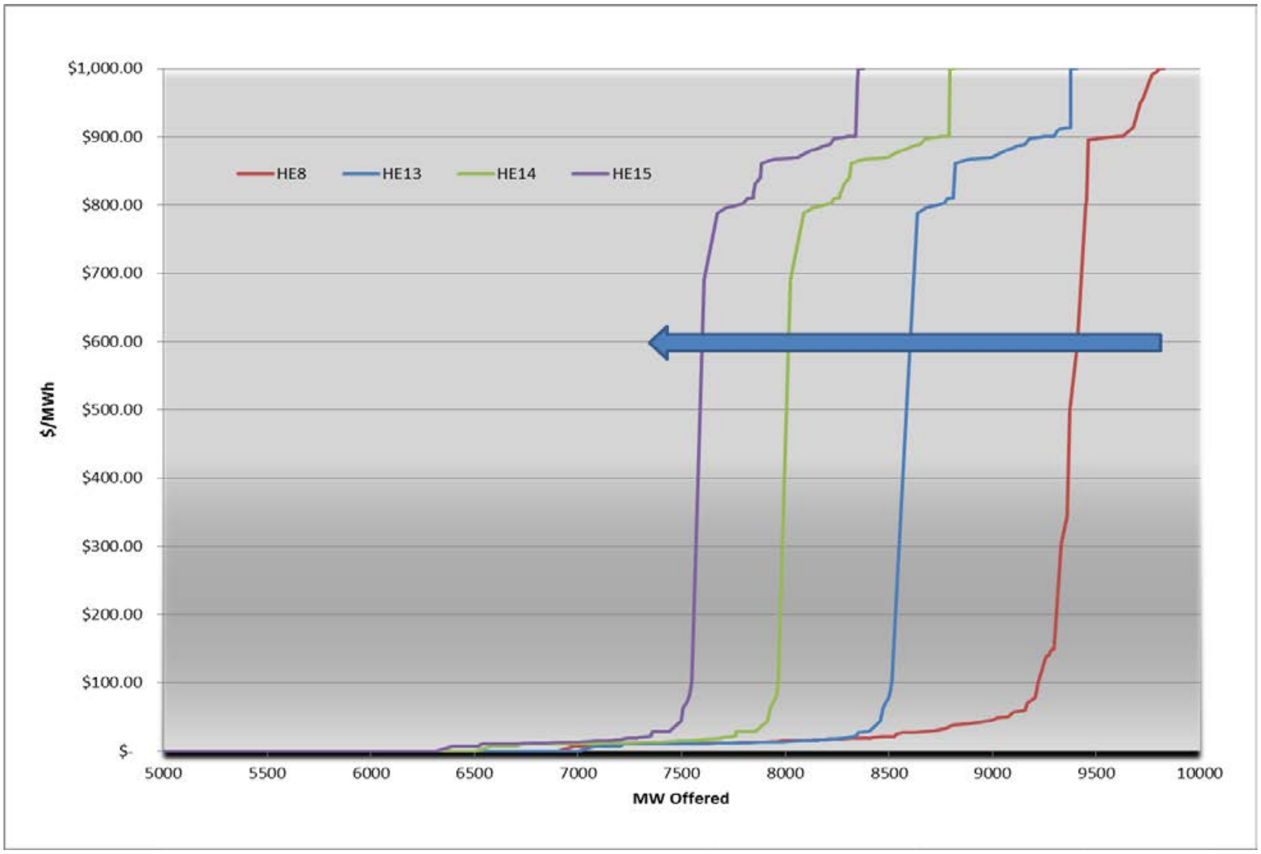
Figure 2: Supply, Demand and Operating Reserves, July 9, 2012



The average pool price for the day was $411.43 (On-Peak $611.20/MWh, Off-Peak $11.90/MWh). This average price is ten times the 30-day rolling average price leading up to July 9. Market conditions remained tight over the next 3 days averaging almost $360/MWh. By that time the 30-day rolling average had more than doubled to $83.88/MWh.

When there is an expectation of a certain amount of market tightness, some generators will withhold in an effort to drive the price higher and run the associated dispatch risk. If the expectation is for a really tight day then there is little need for strategic offers since pure scarcity alone will drive the price. July 9 turned out to be one of the latter. Figure 3 shows the merit orders for several hours in the day and it is apparent that the only significant changes to the shape of the curve through the day is due to the loss of generation as units went on forced outage. There was very little strategic offering that occurred on July 9, 2012.

Figure 3: Offer Curve Development on July 9, 2012



Attachment B - Backgrounder:

Overview of Alberta Electric Operations

Electricity is a commodity, but unlike almost any other commodity it must be produced when it is required, effectively there is no storage. This means that the electricity system must be coordinated to ensure supply and consumption (or demand, usually called 'load' in the electricity business) are matched at all times. That responsibility falls to the Alberta Electric System Operator (AESO). As the name implies, the AESO manages the electric grid in Alberta, directing the operations of market participants within the framework of established rules, procedures and reliability standards. In formal terms, the AESO is responsible for the safe, reliable and economic planning and operation of the Alberta Interconnected Electric System.

The suppliers (generators of electricity in Alberta and importers of electricity generated outside the province) offer their energy into the Alberta electricity marketplace. As the Alberta load rises the AESO will direct generators to produce power to meet that demand. As demand increases the AESO calls upon suppliers who have offered at higher prices. The AESO also contracts for operating reserves to help manage the system and act as a safety net if there is an unplanned loss of generation.

Generation can be lost either to problems at a specific generating plant or where there are problems on the transmission system. Enough reserves are held to deal with the single largest event that could impact the system – the exact criteria are set out in Alberta Reliability Standards which have been developed to ensure a high and consistent standard of reliability (in simple terms, the uninterrupted supply of electricity) across North America. In practice, operating reserves are only one part of how the AESO manages a reliable system. For example: generation and transmission operators must in turn comply with a number of rules and Alberta Reliability Standards. The AESO monitors compliance with these rules and standards and the Market Surveillance Administrator conducts enforcement action in the case of breaches. Adjudication is the function of the Alberta Utilities Commission, a quasi-judicial tribunal.

In practice the contracted reserves and other procedures that the AESO follows are almost always sufficient to deal with the issues that arise from time to time in the electric system. Larger problems occurring over a shorter space of time are obviously more challenging to address. When the AESO anticipates that demand will outstrip supply it follows a 30 step procedure to manage the situation, the last of which is to direct electric distribution companies (the local suppliers of electricity to homes and businesses) to engage in a controlled procedure known as load shedding. This is sometimes also referred to as a 'rolling blackout': the electric distribution companies' stop delivering electricity to some customers for a short period of time before restoring their service and moving to stop delivery at a different set of customers. The AESO directs how much each distribution company needs to stop delivering and the distribution companies in turn determine which customers are selected at any point in time.

If the AESO exhausts all other procedures and load is not shed in a controlled manner, the likely consequence would be a blackout. Lack of control may cause the blackout to cascade forcing other generators and even more load offline and possible affecting neighbouring jurisdictions as happened to Ontario in 2003. Simply put, a controlled load shed is far more preferable to the alternative.

Load shed events do not occur often. Prior to July 9, 2012 the last load shed event in Alberta was July 24, 2006 (398 MW load shed). However, it is important to ensure that market participants and the AESO adhered to the rules and reliability standards designed to protect against such occurrences. The AESO has the responsibility for operating a safe and reliable electric system and therefore has an obvious interest in assessing the circumstances that led to the event with a view to identifying possible improvements in procedures. In the event of breaches in the rules and reliability standards the MSA would consider enforcement action. Even if there are no breaches it is important to check whether lessons can be learned from what are unusual events.

Glossary

Alberta Reliability Standards

The AESO currently operates to North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards in accordance with the Transmission Regulation. NERC standards are adapted for use in Alberta where appropriate through a consultation process led by the AESO, and are subject to approval by the Alberta Utilities Commission as Alberta Reliability Standards.

Alberta Electric System Operator

The Alberta Electric System Operator, abbreviated AESO, as an independent system operator is a not-for-profit entity responsible for the safe, reliable and economic planning and operation of the Alberta Interconnected Electric System. The AESO also facilitates Alberta’s fair, efficient and openly competitive wholesale electricity market.

Independent System Operator Rules

All market participants are obligated to comply with the *Electric Utilities Act* of Alberta and the ISO rules. Each participant is bound by the rules, which are defined as including the rules, practices, policies and procedures that regulate the operation of the market.

Market Participant

Includes any person or entity that supplies, generates, transmits, distributes, trades, exchanges, purchases or sells electricity, electric energy, electricity services or ancillary services.

Alberta Load

The amount of electricity delivered or required within the Alberta Interconnected Electric System at a point in time.

Control Area

Electric power system in which operators such as the AESO match loads to resources within the system, maintain scheduled interchange between control areas, maintain electric frequency within reasonable limits, and provide sufficient generation capacity to maintain operating reserve. The AESO is the Balancing Authority within the Alberta control area.

Design Limits

The operational limit of a product beyond which it not required to function properly.

Operating Limits and Procedures

The technical standards and operating policies and procedures allowing the safe, reliable and economic operation of the Alberta Interconnected Electric System (AIES).

Energy Emergency Alert One
EEA1

This alert is declared after all available resources in the energy market have been used to meet AIES firm load. Sufficient operating reserves are intact - which means we still have about 500 MW in reserves available. Energy is imported through the interconnections with BC and Saskatchewan as per schedules. At this point the AESO would also ask customers who have Demand Opportunity Service (DOS) contracts to lower their demand on the system. These are generally customers who have flexible operations to respond to changes in their demand or supply quickly.

Energy Emergency Alert Two
EEA2

All steps under Alert 1 have been taken. Operating reserves are being used to supply energy requirements. Power service is maintained for all firm load customers. Load management procedures have been implemented, which may include the voluntary load curtailment program (VLCP), voltage reduction and reduction in non-essential loads. Customers who are part of the VLCP have agreed to comply with directives to reduce or stop their power consumption during this type of energy shortfall situation.

A public communication may have been issued to request customers to voluntarily reduce demand. Ancillary service directives have been issued to supplemental and spinning reserves to increase energy supply and firm load is now relied upon for reserve. Emergency energy has been requested of neighbouring control areas. Regulating reserve is maintained.

Energy Emergency Alert Three
EEA3

All steps under Alerts 1 and 2 have been taken. Some firm load is curtailed, which means that power service to some customers is temporarily interrupted to maintain the minimum required regulating reserve and the integrity of the overall system. After receiving directives from the AESO system controller, the distribution facility owners decide which customers are to be temporarily without power at this point in the process.

Load Shedding

The act or process of disconnecting the electric current on certain lines when the demand becomes greater than the supply.

Generator Outage

A temporary suspension or reduction of an electrical generator's output. Outages can be either 'planned', for maintenance, or 'forced' due to unforeseen operational or system problems.

NERC Reliability Standards

North American Electric Reliability Corporation (NERC) reliability standards define the reliability requirements for planning and operating the North American bulk power system, and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities.

Western Electricity Coordinating Council

The Western Electricity Coordinating Council or WECC as it is commonly referred to, is a Regional Entity with delegated authority from NERC responsible for coordinating and promoting bulk electric system reliability in the Western Interconnect that includes Alberta. Pursuant to an agreement with the MSA, WECC monitors the AESO for compliance with the Alberta Reliability Standards.

Operating Reserve

Operating Reserve is output available from a generator that can be dispatched, or load that can be reduced, to maintain system reliability in the event of an imbalance between supply and demand on the electricity system. Most power systems are designed so that, under normal conditions, the operating reserve is always at least the capacity of the largest generator plus a fraction of the peak load.

California

Electrical Emergency Communications

Notification Process for Load Interruptions

Within 24 hours

If possible, issue *Flex Alert* conservation request

FLEXALERT.ORG

Flex Alerts

Funded by the investor-owned utilities and authorized by the CA Public Utilities Commission, Flex Alerts are part of an educational and emergency alert program that informs consumers about how and when to conserve electricity. Go to flexalert.org or caiso.com for more information.

What triggers notification?

- Peak electricity demand forecast
- Generation unavailability
- Loss of generating or transmission facilities
- Adverse weather forecast

NOTIFICATIONS

Restricted Maintenance

Declared when routine maintenance on transmission lines or power plants could threaten grid reliability.

Alert

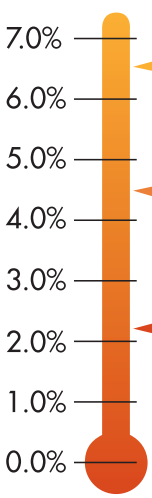
Activated day before ISO may require extra resources to avoid electrical emergency.

Warning

Activated an hour ahead when there may be a shortfall. Conservation requested. Voluntary load reduction programs may be triggered at this point.

Stages of Electrical Emergencies*

Operating Reserves



Stage 1 Emergency — Operating reserves forecast to fall below 6% to 7%

Stronger request for conservation

Stage 2 Emergency — Operating reserves forecast to be less than 5%

Indicates reserves are forecast to be below minimum criteria and requires ISO intervention in the market

Stage 3 Emergency — Operating reserves forecast to be less than 3%

Issue notice of potential load interruptions to utilities

***Transmission Emergencies** — Many emergencies are tied to electric supply and operating reserve levels within the balancing authority, however *some emergencies are declared as a result of transmission line overloads, losses, or limitations.*

Go to www.caiso.com for the latest grid emergency information. Sign up to receive grid notifications by clicking "Notify me" on our home page.

California ISO Shaping a Renewed Future	Operating Procedure	Procedure No.	4420
		Version No.	8.4
		Effective Date	1/09/14
System Emergency (Formerly E-508, E-509)		Distribution Restriction: None	

Table of Contents

Purpose

This procedure outlines the steps that may be taken to prevent a System Emergency and to stabilize the system should a System Emergency occur.

1. Responsibilities

CAISO Shift Supervisor	Directs timely and appropriate Real-Time actions necessary to ensure reliable operation of the CAISO Controlled Grid and Balancing Authority Area.
CAISO System Operator (NERC Certified Real-Time Operating Personnel)	Ensures reliable operation of the CAISO Controlled Grid and Balancing Authority Area.
Participating Transmission Owners (PTOs)	Maintain a single point of contact with the CAISO through their Power Grid Operations Centers and are subject to Transmission Operator Directives issued by the CAISO.
Utility Distribution Companies (UDCs) and Small UDCs	Comply with all directions from the CAISO concerning the management of System Emergencies, as per the CAISO Tariff.
Participating Generators and Scheduling Coordinators	Follow all operating instructions and is subject to directives issued by the CAISO during a System Emergency and any circumstances in which the CAISO considers that a System Emergency is imminent, anticipated or threatened, as per the CAISO Tariff.

2. Scope/Applicability

2.1. Background

Power system disturbances typically occur due to the loss of generating equipment, transmission facilities, or unexpected load changes. These disturbances may affect the reliable operation of the CAISO Controlled Grid and the WECC interconnected Bulk Electric System. Severe system disturbances generally result in critically loaded transmission facilities, significant frequency deviations, high or low voltage conditions, or stability problems.

2.2. Scope/ Applicability

This procedure outlines the steps that may be taken to prevent a System Emergency and to stabilize the system should a System Emergency occur. A System Emergency can consist of a Transmission Emergency or a Staged Emergency, and may be sudden or progressive in nature.

To prevent a System Emergency, and to maintain system reliability, the CAISO may issue a restricted maintenance operations, Alert, or Warning notice.

3. Procedure Detail

The order of the actions taken may vary due to system conditions or other operational issues. It may be necessary to skip actions due to the severity of the situation. To the extent possible, and when prudent, actions that were skipped may be implemented at a later time or date.

3.1. Restricted Maintenance Operations

Restricted maintenance operations apply to all pre-scheduled Outages and/or any planned maintenance.

Restricted maintenance operations apply to PTO Control Centers, Scheduling Coordinators and Participating Generators, for the hours identified in the notice. Restricted maintenance operations are applied for the shortest duration necessary to meet the reliability concern.

The CAISO maintains the authority to cancel or postpone any or all or work to preserve overall System Reliability, both prior to Real-Time and during Real-Time operations. The CAISO will declare restricted maintenance operations when deemed necessary.

Step	CAISO System Operator Actions
1	**Issue** a Restricted Maintenance Operations or a Generation Restricted Maintenance Operations notice using the AWE Notification System.
2	**Notify** WECC RC by phone.
3	**Notify** the WECC ALL RELIABILITY distribution list via WECCNet.
4	**Consider** postponing outages or returning equipment to service early.
5	**Cancel** outages as needed to maintain system reliability.
6	**Only approve** outages that will have no negative or potential negative effect on system reliability.
7	**Utilize** Exceptional Dispatch to mitigate as necessary.
8	**Utilize** Manual Dispatch on the Interties to mitigate as necessary.
9	**Continue** to monitor the system. If conditions deteriorate, **consider** issuing an Alert, Warning, Transmission Emergency, or Staged Emergency notice.
10	When conditions allow, **back out** of each step performed, **notify** the WECC RC by phone and **terminate** the Restricted Maintenance.
11	**Refer** to 4420 System Emergency attachments.

Step	PTO Control Centers, Scheduling Coordinators and Participating Generators
12	**Obtain** permission from the CAISO to proceed with pre-scheduled or planned work, regardless of whether prior approvals were obtained from the CAISO.
Note*: Outages postponed due to the issuance of a restricted maintenance operations notice may be considered for re-scheduling outside of the previously pre-scheduled Outage hours and/or outside of the hours of restricted maintenance operations.*	

3.2. Transmission Emergency

The CAISO may declare a Transmission Emergency for any event that threatens, harms, or limits the capabilities of any element of the transmission grid and overall grid reliability. Declaration of a Transmission Emergency may be caused by events including but not limited to:

- Transmission line/path overloads or loss (including exceeding Interconnection Reliability Operating Limits (IROL) and System Operating Limits (SOL))
- Transformer overloads or loss
- Instability
- Frequency deviations or decay
- Voltage that exceeds or falls below predetermined limits
- Fires, earthquake, severe weather, sabotage, civil unrest, terrorism

The CAISO System Operator may take, but is not limited to, the following actions **in any order** needed, and to the extent necessary, to prevent, mitigate or otherwise manage a System Emergency:

Step	CAISO System Operator Actions
1	**Issue** a Transmission Emergency notice using the AWE Notification System.
2	**Notify** WECC RC by phone.
3	**Notify** the WECC ALL RELIABILITY distribution list via WECCNet.
4	**Consider** postponing outages or returning equipment to service early.
5	**Cancel** outages as needed to maintain system reliability.
6	**Only approve** outages that will have no negative or potential negative effect on system reliability.

7	**Exhaust** available resources (except for Spin/Non-Spin) through the market.
8	**Utilize** Exceptional Dispatch to mitigate as necessary.
9	**Utilize** Manual Dispatch on the Interties to mitigate as necessary.
10	**Call** on available Demand Response programs and UDC Interruptible Load (Non-Firm) programs (amount varies). This requires at least a 30 minute notification. **Refer** to CAISO Operating Procedure 4510 Load Management Programs and Underfrequency Load Shedding and its attachments.
11	**Reduce** participating pump load as available.
12	**Utilize** Spinning and Non-Spinning Reserve resources.
13	**Dispatch** effective Condition 2 RMR Units and **notify** market participants if they are used for System or Competitive Path mitigation.
14	**Request** emergency assistance from adjacent Balancing Authority Areas as necessary. **Refer** to 4410 Emergency Assistance.
15	**Request** effective available Energy from MSS resources, if necessary.
16	**Utilize** Firm Load interruption, if necessary.
17	**Issue** a Transmission Emergency – Firm Load Interruptions notice using the AWE Notification System.
18	**Advise** PTOs that they can take local control of Generating Resources to prevent islanding or to stabilize islands. This may require PTOs to suspend the code of conduct.
19	When conditions stabilize, **back out** of each step performed, **notify** the WECC RC by phone, the WECC ALL RELIABILITY distribution list via WECCNet, and **terminate** the Transmission Emergency – Firm Load Interruptions and the Transmission Emergency.

3.3. Operating Reserve Deficiency

The CAISO maintains and, in case of deployment, restores operating reserves to the levels specified in WECC Standard BAL-STD-002.

3.3.1. Alert Notice

The CAISO issues an Alert notice by 1500 hrs the day before anticipated operating reserve deficiencies, along with appropriate notifications.

Note: The 24 Hour Forecast notice has been combined with the Alert Notice.

The CAISO System Operator may take, but is not limited to, the following actions **in any order** needed:

Step	CAISO System Operator Actions
1	**Issue** an Alert notice using the AWE Notification System.
2	**Notify** WECC RC by phone.
3	**Notify** WECC ALL RELIABILITY distribution list via WECCNet.
4	**Notify** PTOs by phone.
5	**Request** through a MNS market message that SCs bid in any additional available capacity to the CAISO.
6	**Issue** a "Flex Alert" notice using the AWE Notification System, if needed.
7	**Evaluate** need for restricted maintenance operations.

3.3.2. Warning Notice

The CAISO issues a Warning notice when the Real-time Market run results indicate that Operating Reserves are anticipated to be less than WECC Operating Reserve requirements and further actions are necessary to maintain the Operating Reserve requirements.

The CAISO System Operator may take, but is not limited to, the following actions **in any order** needed, and to the extent necessary, to prevent, mitigate or otherwise manage a System Emergency:

Step	CAISO System Operator Actions
1	**Issue** a Warning notice using the AWE Notification System.
2	**Notify** WECC RC by phone and **request** they declare an Energy Emergency Alert 1 (EEA-1) for the CISO BA area.
3	**Notify** WECC ALL RELIABILITY distribution list via WECCNet.
4	**Notify** PTOs by phone.
5	**Issue** a Flex Alert notice using the AWE Notification System, as needed.
6	**Exhaust** available resources (except for Spin/Non-Spin) through the market. **Use** Exceptional Dispatch as needed.
7	**Reduce** participating pump load as available.

8	**Dispatch**, as necessary, available unloaded generation Capacity without RT Energy Bids. This can include Exceptional Dispatch on a resource subject to CPM designation.
9	**Call** IOUs to dispatch available generation to full Load.
10	**Dispatch** Non-Spinning and Spinning Reserve resources, including contingent only, to the extent possible while maintaining required Operating Reserves.
11	**Dispatch** Condition 2 RMR Units and **notify** market participants of the use of Condition 2 RMR for system needs.
12	**Call** on available Demand Response programs and UDC Interruptible Load (Non-Firm) programs (amount varies). This requires a 30 minute notification. **Refer** to CAISO Operating Procedure 4510 Load Management Programs and Underfrequency Load Shedding and its attachments.
13	**Canvas** other entities and Balancing Authorities for available Manual Dispatch Energy/Capacity on interties**.**
Warning Notice Actions with Emergency Stage 1 Imminent	
14	**Request** WECC RC to issue an Energy Emergency Alert 2 (EEA-2) for the CISO BA area.

3.3.3.Emergency Stage 1

The CAISO issues an Emergency Stage 1 when Operating Reserve shortfalls exist or are forecast to occur, and available market and non-market resources are insufficient to maintain Operating Reserve requirements. The actions identified below will be taken as needed to restore or maintain required Operating Reserves.

The CAISO System Operator may take, but is not limited to, the following actions **in any order** needed, and to the extent necessary, to prevent, mitigate or otherwise manage a System Emergency:

Step	CAISO System Operator Actions
1	**Issue** an Emergency Stage 1 notice using the AWE Notification System.
2	**Notify** WECC RC by phone.
3	**Notify the** WECC ALL RELIABILITY distribution list via WECCNet.
4	**Establish** conference call with PTOs (may use California Hotline, also known as Intertie 137).
5	**Issue** a Flex Alert notice using the AWE tool, as needed.

6	**Request** WECC RC to issue a WECC RC notice that Emergency Assistance may be required by the CAISO, -and- **Request** that other Balancing Authorities determine the amount of assistance they are able to provide.
7	**Evaluate** the impacts of any in-progress Time Error Correction and **request** the WECC RC terminate Time Error Correction if it is contributing to resource deficiency.
8	**Request** all available Energy from NCPA (Load Following MSS) Resources.

3.3.4. Emergency Stage 2

The CAISO issues an Emergency Stage 2 when it has taken all actions listed above and cannot maintain its Non-Spinning Reserve requirement as indicated by the EMS system. The actions identified below will be taken in an effort to restore the required Operating Reserves.

The CAISO System Operator may take, but is not limited to, the following actions **in any order** needed, and to the extent necessary, to prevent, mitigate or otherwise manage a System Emergency:

Step	CAISO System Operator Actions
1	**Issue** an Emergency Stage 2 notice using the AWE Notification System.
2	**Notify** WECC RC by phone.
3	**Notify** the WECC ALL RELIABILITY distribution list via WECCNet.
4	**Establish** conference call with PTOs (may use California Hotline, AKA Intertie 137).
5	**Evaluate** the impacts of any in-progress Time Error Correction and **request** WECC RC to terminate Time Error Correction if it is contributing to resource deficiency.
6	**Issue** a 1-Hour Probability notice using the AWE Notification System to notify utilities of anticipated Stage 3 event that may occur if anticipated in the next 90 minutes.
7	**Procure** RMR and any other available Out-of-Market Spinning and Non-Spinning reserves as available.
8	**Dispatch** Non-Spinning reserves, including contingent only, as necessary.
Emergency Stage 2 Actions with Stage 3 Imminent	
9	**Procure** Emergency Assistance per CAISO Operating Procedure 4410 Emergency Assistance.

10	**Request** WECC RC to issue an Energy Emergency Alert 3 (EEA-3) for the CISO BA area.
11	**Pre-arrange** (whenever possible) firm load dropping with UDC/MSS in order to minimize any time-lag in dropping load, at the direction of the CAISO Shift Supervisor. Example: On a peak-load day where it is anticipated that Stage 3 Emergency Firm load reductions are needed, there will be an early morning reliability conference call to advise the PTOs to attend stations and/or standby at facilities, as required, to support immediate load dropping at the direction of the CAISO Shift Supervisor.

3.3.5. Emergency Stage 3

The CAISO issues an Emergency Stage 3 when the Spinning Reserve portion of the Operating Reserve depletes, or is anticipated to deplete below the WECC Operating Reserve requirement and cannot be restored. The WECC Operating Reserve requirement states that Spinning Reserve shall be no less than 50% of the total Operating Reserve requirements.

The CAISO System Operator may take, but is not limited to, the following actions **in any order** needed, and to the extent necessary, to prevent, mitigate or otherwise manage a System Emergency:

Step	CAISO System Operator Actions
1	**Issue** an Emergency Stage 3 notice using the AWE Notification System.
2	**Notify** WECC RC by phone.
3	**Notify** the WECC ALL RELIABILITY distribution list via WECCNet.
4	**Establish** conference call with PTOs (may use California Hotline, AKA Intertie 137).
5	**Request** WECC RC to declare CAISO Energy Emergency Alert 3 (EEA-3).
6	**Initiate** Firm Load Interruptions. **Provide** the megawatt quantity to be interrupted to each UDC/MSS. Interruptions should occur in rotating blocks and are dependent on Operating Reserve requirements and/or ACE/frequency. **Refer** to CAISO Operating Procedure 4510A Load Shed Calculation Guideline

7	**Issue** a Stage 3 System Emergency – Firm Load Interruptions notice using the AWE Notification System.
8	Using MNS, **notify** Market Participants of the total amount of load interruptions requested, in MW, for the CAISO BA.

3.4. Emergency Downgrade

The CAISO will make notifications and downgrade (step down) to necessary level of emergency as conditions improve, or cancel the System Emergency and return to normal operations.

4. Supporting Information

Operationally Affected Parties

Shared on the internet.

References

Resources studied in the development of this procedure and that may have an effect upon some steps taken herein include but are not limited to:

CAISO Tariff	7.7.1, 7.7.2.1, 7.7.2.2, 7.7.2.3, 7.7.3.1, 7.7.3.2, 7.7.11
CAISO Operating Procedure	4410 Emergency Assistance 4510 Load Management Programs and Underfrequency Load Shedding 4510A Load Shed Calculation Guideline
NERC Standards	BAL-004 Time Error Correction EOP-002 R2, R3, R4, R6, R7.1, R7.2 EOP-003 R1, R3 PER-001 R1 TOP-001 Reliability Responsibilities and Authorities
WECC Standards	BAL-STD-002 Operating Reserves

Definitions

Unless the context otherwise indicates, any word or expression defined in the Master Definitions Supplement to the CAISO Tariff shall have that meaning when capitalized in this Operating Procedure.

The following additional terms are capitalized in this Operating Procedure when used as defined below:

None

Version History

Version	Change	By	Date
6.0	Annual Review, replaced "WECC Operating Requirements" with "MSSC Requirements" in the Regional Reserve Deficiency section, replaced specific Operators/Dispatchers to "System Operator", added "System Operator" to Definitions, realigned action steps in order of priority, aligned NERC Energy Emergency Alerts to be consistent with E-508 Warning/Emergency sequence, aligned E-508 with E-508B, validated procedure current, correct and up to date.		6/16/10
7.0	Reformatting for new prototype		1/20/11
7.1	Changed Purpose statement to original found in E-508, added Policy section from E-508 to Scope/Applicability section. Deleted Transmission Emergency section (section 1.0 in E-508). On 5/1/11, 4420 (E-508), Added Responsibilities, Scope/Applicability, and Periodic Review Criteria. Section 1-4 from E-508 moved to section 3.0. Added Transmission Emergency section from E-508 and placed in section 1.0 and removed Transmission Emergency content from System Emergency content in section 3.1. Policy from E-508 moved to Scope/Applicability.		6/2/11
8.0	**<u>Major Rewrite:</u>** Provided clarification regarding when we issue Alerts, Warnings, and Stages1, 2, & 3 Emergencies. Merged the 24 Hour Forecast Notice with the Alert Notice Added language for Demand Response under the Warning section, "Warning with a Stage 1 Imminent" steps. Merged 4220 Restricted Maintenance Operations (RMO) procedure with 4420. RMO is under section 3.1 **<u>Attachment B</u>** changes: Added RMO Section at the beginning		5/14/12

	Provided clarification regarding when we issue Alerts, Warnings, and Stages1, 2, & 3 Emergencies. Updated steps throughout Added language for Demand Response under the Warning section, "Warning with a Stage 1 Imminent" steps. Merged the 24 Hour Forecast Notice with the Alert Notice **Attachment C**: added flex alert, added Load interruption Templates for Stage 3 Emergency and Transmission Emergency template, and deleted 24 hrs forecast template, and deleted system emergency template. **Attachment D**: retired **New Attachments E, F, G**: Contents haven't changed. These were previously attachments to 4220 Restricted Maintenance Operations so now they are becoming attachments to this procedure due to the merge.		
8.1	Section 3.2 CAISO System Operator Actions: Added step to issue a Transmission Emergency-Load Interruption notice Section 3.3.5 CAISO System Operator Actions: Added a step to issue a Stage 3 System Emergency-Load Interruptions notice Section 3.3.2 CAISO System Operator Actions, step 13: revised step to add Demand Response programs **Attachment B** changes: Added language for Demand Response under the Warning section, "Warning with a Stage 1 Imminent" steps. Added a step to issue a Stage 3 System Emergency-Load Interruptions notice, and added a step to issue a Transmission Emergency-Load Interruptions notice **Attachment C** changes: added two		5/31/12

	templates: Stage 3 System Emergency-Load Interruptions Cancellation notice and Transmission Emergency-Load Interruptions Cancellation notice		
8.2	Updated references to procedure 4510 and to the Stage 3 System Emergency – Firm Load Interruptions notice and to the Transmission Emergency – Firm Load Interruptions notice. **Attachments B and C**: same updates.		8/27/12
8.3	Section 3.2 – added reference to Demand Response Programs and deleted step 16 referencing PG&E Commercial & Industrial Customer Voluntary Conservation Program > 300 kW Section 3.3.2 – moved step 13 to call on available Demand Response programs ahead of step 12 to "Canvas other entities and Balancing Authorities"		7/1/13
8.4	Section 3.2 step 11 and section 3.3.2 step 7 – added "participating"		1/09/14

5. Periodic Review Procedure

Review Criteria There are no specific review criteria identified for this procedure, follow instructions in Procedures 5510 and 5520.

Frequency Review as recommended in Procedures 5510 and 5520.

Incorporation of Changes There are no specific criteria for changing this document, follow instructions in Procedures 5510 and 5520.

Technical Review

Reviewed By Content Expert	Signature	Date
Operations Procedures		12/20/13
Real-Time Ops		1/06/14
DA Operations, Scheduling Services and Outage Management		5/4/12

***Signed previous version only, changes to this version were minor and did not require full signature approval.**

Approval

Approved By	Signature	Date
Director, Operations Engineering Services		5/1/12
Director, System Operations		5/5/12

*Signed previous version only, changes to this version were minor and did not require full signature approval.

Appendix

Attachments:

- 4420B Alert/Warning/Emergency (AWE) Guide
- 4420C System Emergency Notice Templates
- 4420E Allowable Transmission Maintenance Activities During Restricted Maintenance Operations
- 4420F SONGS Essential Component List
- 4420G Diablo Canyon Essential Component List

ROTATING OUTAGES: FAQs

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

Q. What is a rotating outage?

A. A rotating outage is a temporary and scheduled electric outage conducted under utility control that lasts approximately one hour, depending on circumstances. A utility manages and rotates the outages to protect the integrity of the overall electric system.

Q. Why would Southern California Edison (SCE) need to resort to rotating outages?

A. Controlled, rotating outages can become necessary when the California Independent System Operator (CAISO) declares a Stage 3 Emergency. Under these circumstances, without controlled, rotating power outages on a relatively small scale, a widespread disturbance to the electric grid could occur, which would lead to uncontrolled, large-scale outages.

Q. How will I be notified about a Stage 3 Emergency declaration?

A. As soon as the Stage 3 Emergency is declared, SCE will contact the news media, especially radio and television stations, which are encouraged to broadcast the news immediately. Because SCE may have as few as 10 minutes after a Stage 3 Emergency is declared before rotating outages begin, individual notifications are not possible. You can also contact SCE at 1-800-611-1911 to find out whether your neighborhood is part of a current controlled outage. You can also find out if your rotating outage group is being called by visiting www.sce.com

Q. How does the rotation work?

A. SCE identified the circuits available for use in rotating outages according to California Public Utilities Commission rules. A circuit is an electrical line that supplies power to a combination of residential and/or commercial customers within a given geographical area. These circuits have been arranged into groups. The amount of power the CAISO designates for curtailment will determine the number of groups that are interrupted at any one time. The groups will be interrupted, as operating conditions permit, and each outage is expected to last about one hour. At the end of the hour, service will be restored to the affected groups and the next groups on the list will be interrupted to maintain the amount of load requested by the CAISO. Once a group has been used in a rotating outage, it is moved to the bottom of the list.

Q. How are circuits selected?

A. Most of SCE's circuits are subject to rotating outages. Some "Essential Use Customers" who provide critical public health, safety, and security services (such as hospitals) are exempted from these outages. All remaining circuits are arranged into groups that represent all customer types (i.e., residential, commercial and industrial) and are dispersed throughout SCE's 50,000-square-mile service area. However in a transmission emergency, all circuits are subject to outages.

Q. Is there any way I can find out when I might be affected?

A. Your Rotating Outage Group is located on your bill. Summary Bill customers will find this information in the "Details" portion of their bill. At sce.com, you may find the next groups in line to be rotated. As soon as the CAISO notifies SCE of a pending outage, the information is posted on www.sce.com.

Q. Will customers who require life support (or other special medical equipment) be subject to outages?

A. SCE cannot guarantee uninterrupted service to any customer; however, it does keep track of all customers who have applied for, and been certified as, "critical care" customers (those who cannot be without electric service for more than 2 hours) pursuant to the Medical Baseline program. Medical Baseline customers are not exempt from rotating outages. It is important that your emergency plan includes having a sufficient standby battery or back-up portable unit available to power your in-home medical equipment. If you have back-up power generation, test it each month to ensure it is ready in case of an emergency. If you do not have back-up generation, please plan to visit a Cooling Station to ensure that you have continued access to electricity.

For more information about outages, visit **www.sce.com/info/PowerOutages**.

Ontario

Market Rules

Chapter 5

Power System Reliability

Power to Ontario.
On Demand.

Library Record No.	MDP_RUL_0002_05
Document Name	Market Rules for the Ontario Electricity Market
Issue	Issue 27.0
Reason for Issue	Baseline 30.0
Effective Date	September 11, 2013

Document Change History

Issue/Draft	Reason for Issue	Date
Issue 1.0	Baseline 8.0	September 25, 2002
Issue 2.0	Baseline 8.1	December 5, 2002
Issue 3.0	Baseline 9.0	March 5, 2003
Issue 4.0	Baseline 9.1	June 4, 2003
Issue 5.0	Baseline 10.0	September 10, 2003
Issue 6.0	Baseline 10.1	December 10, 2003
Issue 7.0	Baseline 11.1	June 2, 2004
Issue 8.0	Baseline 13.0	March 9, 2005
Issue 9.0	Baseline 14.1	December 7, 2005
Issue 10.0	Baseline 15.0	March 8, 2006
Issue 11.0	Baseline 16.0	September 13, 2006
Issue 12.0	Baseline 16.1	December 6, 2006
Issue 13.0	Baseline 17.0	March 7, 2007
Issue 14.0	Baseline 18.0	September 12, 2007
Issue 15.0	Baseline 18.1	December 12, 2007
Issue 16.0	Baseline 19.0	March 5, 2008
Issue 17.0	Baseline 20.0	September 10, 2008
Issue 18.0	Baseline 22.0	September 9, 2009
Issue 19.0	Effective date for MR-00366	May 8, 2010
Issue 20.0	Baseline 23.1	June 2, 2010
Issue 21.0	Effective date for MR-00379	July 8, 2011
Issue 22.0	Baseline 27.0	March 7, 2012
Issue 23.0	Baseline 27.1	June 6, 2012
Issue 24.0	Baseline 28.1	December 5, 2012
Issue 25.0	Baseline 29.0	March 6, 2013
Issue 26.0	Baseline 29.1	June 5, 2013
Issue 27.0	Baseline 30.0	September 11, 2013

Related Documents

Library Record No.	Document Title	Version
MDP_RUL_0002	Market Rules for the Ontario Electricity Market	52.0

Document Control

Authorities

Prepared by
Market Evolution

Reviewed by
Technical Panel
Legal Affairs
IESO Change Management

Approved by
IESO Board

Distribution List

Name	**Organization**

Table of Contents

1. Purposes, Interpretation and General Principles

1.1 Purposes of Chapter 5 and Interpretation

1.1.1 Pursuant to section 5 of the Electricity Act, 1998, one of the objects of the *IESO* is to maintain the *reliability* of the *IESO-controlled grid*. This Chapter of the *market rules* sets forth:

1.1.1.1 rules governing maintenance of the *reliability* of the *IESO-controlled grid*;

1.1.1.2 conditions under which the *IESO* shall have authority to intervene in the *IESO-administered markets* and issue directions to *market participants* so as to maintain the *reliability* of the *IESO-controlled grid* and of electricity service;

1.1.1.3 procedures to be used by the *IESO*, including the issuance of directions, in the event of an *emergency*, an *emergency operating state* or a *high-risk operating state;*

1.1.1.4 minimum requirements for communication and information exchange between the *IESO* and *market participants* relating to the *reliability* of the *IESO-controlled grid*; and

1.1.1.5 the *IESO's* reporting requirements associated with its responsibilities for maintaining the *reliability* of the *IESO-controlled grid*.

1.1.2 For the purposes of this Chapter, “maintaining” *reliability* shall include re-establishing or restoring *reliability* and “maintain” and “maintenance” shall be interpreted accordingly.

1.1.3 In the event of a contradiction or inconsistency between the provisions of this Chapter 5 and any other provision of the *market rules*, the provisions of this Chapter 5 shall govern. In performing any act, power, or duty under the *market rules*, the *IESO* shall have due regard to and, when necessary to ensure the *reliability* of the *IESO-controlled grid*, give precedence to the provisions of this Chapter 5.

1.2 General Principles

1.2.1 To the fullest extent possible consistent with maintaining the *reliability* of the *IESO-controlled grid*, the *IESO* shall apply the *market rules* relating to *reliability* so as to minimize the *IESO's* intervention into the operation of the *IESO-administered markets*. However, the maintenance of a *reliable IESO-controlled grid* shall be considered of paramount importance under these *market rules*, and the *IESO* shall have authority to intervene in the *IESO-administered markets* to the extent necessary to maintain the *reliability* of the *IESO-controlled grid*.

1.2.2 In all cases, except as otherwise noted in this Chapter, where the *IESO* takes action under this Chapter, it shall attempt to coordinate its actions with affected *market participants* unless, in the *IESO's* opinion, conditions dictate the need for immediate action.

1.2.3 Nothing in this Chapter is intended to prevent *market participants* from acting to protect their assets from physical damage or to protect the safety of their employees, the public or the environment, provided that any such actions that may affect the *reliability* of the *IESO-controlled grid* are coordinated with the *IESO* to the fullest extent practicable and are, in any event, reported or notified to the *IESO* where required by these *market rules* to be so reported or notified.

1.2.4 Section 7.5 of Chapter 1 does not apply to this Chapter and any action or event that is required to occur on or by a stipulated time or day under this Chapter, or under a direction, instruction or order of the *IESO* issued pursuant to this Chapter, shall occur on or by that time, whether or not a business hour, or on or by that day, whether or not a *business day*, unless otherwise specified in this Chapter.

1.2.5 Unless a direction, instruction or order of the *IESO* provides otherwise, wherever this Chapter specifies that an action is to be taken "promptly" or "immediately”, such action shall be taken as soon as possible after receiving the direction, instruction or order from the *IESO* or after becoming aware that an action is to be taken or is required not to be taken but in all events within five minutes, subject only to delay necessitated by concerns for the safety of equipment, employees, the public or the environment.

1.2.6 Subject to section 1.2.7, *reliability standards* established by a *standards authority* that have not otherwise been stayed or revoked and referred back to the *standards authority* for further consideration by the *Ontario Energy Board* shall be declared in force in Ontario upon the later date of:

1.2.6.1 the *reliability standards* being declared in force in the United States or, for *NPCC* reliability criteria, when declared in force by *NPCC*; and

1.2.6.2 the expiry of the period for initiating a review before the *Ontario Energy Board* and the conclusion of any such review*;*

and shall cease to be in force in Ontario when they cease to be in force in the United States, provided that where a *reliability standard* is being retired and replaced with a new or amended version, the previous version shall remain in effect in Ontario until the later of the completion of the conditions in sections 1.2.6.1 and 1.2.6.2.

1.2.7 Notwithstanding section 1.2.6, where a *reliability standard* approved by *NERC* failed to achieve approval by the *NERC* registered ballot body as specified in *NERC*'s Rules of Procedure, the *reliability standard* will not be in force in Ontario unless and until the *IESO* determines, in consultation with affected *market participants*, that all or part of the *reliability standard* is in force in Ontario. The *IESO* shall *publish* notice of its determination and where applicable, such *reliability standard* will come into effect in accordance with section 1.2.6.

2. IESO-Controlled Grid and Operating States

2.1 Scope of IESO-Controlled Grid

2.1.1 The specific *facilities* included within the *IESO-controlled grid* shall be identified in the *operating agreements* between the *IESO* and each *transmitter* that are entered into in accordance with the Electricity Act, 1998. To the extent the *IESO* concludes, on its own initiative or further to a request made by a *market participant*, that, in order to meet its obligations to *reliably* operate the *IESO-controlled grid* or administer the *IESO-administered markets*, additional *transmission systems* or distribution *facilities* should be included within the *IESO-controlled grid*, the *IESO* shall negotiate to amend the applicable *operating agreement* to include such *transmission systems or facilities* or to conclude an *operating agreement* with the *transmitter* or owner of such *facilities* with whom no *operating agreement* has yet been concluded, as the case may be.

2.1.2 Subject to the licence of the *IESO* or of the applicable transmitter or distributor, if the *IESO* and a *transmitter* or *distributor* are unable to reach agreement on the inclusion of *facilities* within the *IESO-controlled grid*, the matter shall be resolved using the dispute resolution procedures in the applicable *operating agreement* or, in the absence of same, the procedures set forth in Section 2 of Chapter 3.

2.2 Normal Operating State

2.2.1 The *IESO-controlled grid* shall be considered as being in a *normal operating state* when:

2.2.1.1 the voltage magnitudes at all energized busbars at any switchyard or substation of the *IESO-controlled grid* are within the ratings set by relevant *transmitters*;

2.2.1.2 the current flows on all transmission *facilities* of the *IESO-controlled grid* are within the equipment ratings established by the relevant *transmitters*;

2.2.1.3 all other electric plant forming part of, or having or likely to have a material impact on the operation of, the *IESO-controlled grid* is being operated within the equipment ratings defined by the relevant *transmitters*, *generators* and *distributors*;

2.2.1.4 all *interconnected systems* having or likely to have a material impact on the operation of the *IESO-controlled grid* are being operated within the equipment ratings that are jointly established between the *IESO* and the relevant *transmitters*;

2.2.1.5 the configuration of the *IESO-controlled grid* is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and

2.2.1.6 conditions on the *IESO-controlled grid* are secure in accordance with the requirements set forth in Section 5.

2.3 Emergency Operating State

2.3.1 The *IESO-controlled grid* shall be considered as being in an *emergency operating state* when observance of *security limits* under a *normal operating state* will either:

2.3.1.1 require curtailment of *non-dispatchable load*; or

2.3.1.2 restrict transactions on interconnected systems during an emergency on the IESO-controlled grid or on a neighbouring electricity system.

2.3.2 The *IESO* shall not take any action or refrain from taking any action that will, in the *IESO*'s opinion, be reasonably likely to lead to an *emergency operating state*.

2.3.3 The *IESO* shall promptly inform *market participants* when an *emergency operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During an *emergency operating state*, the *IESO* shall have the authority to modify *security limits* as necessary to manage conditions on the *IESO-controlled grid*, and to take such other action or refrain from taking such other action consistent with *good utility practice* as may be required to restore the *IESO-controlled grid* to a *normal operating state* and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

2.3.3A Without limiting the generality of section 2.3.3 and notwithstanding any other provision of the *market rules*, the *IESO* may, when the *IESO-controlled grid* is in an *emergency operating state*, acquire *emergency energy* in accordance with all applicable *reliability standards* and any applicable *interconnection agreement* in order to maintain the *reliability* of the *IESO-controlled grid.* The *IESO* shall not exercise this power where *market participants* have *offered* to provide sufficient quantities of *energy*, eligible for *dispatch* or scheduling, to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*. The costs associated with the acquisition of such *emergency energy* paid by the *IESO* pursuant to the applicable *interconnection agreement* shall be recovered in accordance with section 4.8 of Chapter 9.

2.3.4 Further provisions relating to system and market operations during *emergency* conditions are set forth in Chapter 7.

2.4 High-Risk Operating State

2.4.1 The *IESO-controlled grid* shall be considered to be in a *high-risk operating state* when the observance of *security limits* under a *normal operating state* will expose the *integrated power system* to a significantly higher than normal probability of one or more *contingency events* and associated consequences, or of a condition that may lead to, but is not yet, an *emergency*. The conditions under which the *IESO-controlled grid* may be considered as entering into or exiting a *high-risk operating state* shall be defined in the *IESO*'s operating procedures, it being understood that, without limiting the generality of the foregoing, a *high-risk operating state* is normally associated with adverse weather conditions (such as lightening or freezing rain), extreme weather conditions (such as tornadoes or hurricanes) or equipment-related problems (such as the operation of equipment known to be unreliable or defective).

2.4.2 The *IESO* shall not take any action or refrain from taking any action that will, in the opinion of the *IESO*, be reasonably likely to lead to a *high-risk operating state*.

2.4.3 The *IESO* shall promptly inform *market participants* when a *high-risk operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During a *high-risk operating state*, the *IESO* shall have the authority to modify *security limits* as necessary to manage conditions on the *IESO-controlled grid*, and to take such other action or refrain from taking such other action consistent with *good utility practice* as may be required and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

3. Obligations and Responsibilities

3.1 Objectives

3.1.1 This section 3 sets forth the responsibilities, obligations and authorities of the *IESO* and each *market participant* in order to maintain the *reliability* of the *IESO-controlled grid*.

3.2 Obligations of the IESO

3.2.1 The *IESO* shall direct the operations of the *IESO-controlled grid* pursuant to the provisions of all applicable *operating agreements* and shall maintain the *reliability* of the *IESO-controlled grid*. The *IESO's* responsibilities in this regard shall include, but are not limited to, the monitoring of, and the issuing of orders, directions or instructions to *dispatch generation, dispatchable loads,* distribution *facilities* and transmission *facilities* on the *IESO-controlled grid*.

3.2.2 The *IESO* shall carry out its obligations in accordance with all applicable *reliability standards.*

3.2.3 In order to meet its obligations under this Chapter and under other provisions of the *market rules*, the *IESO* shall maintain written operating procedures and instructions and shall make same available for inspection at all times by *market participants*. The Board of Directors of the *IESO* may *amend* the *market rules* to include any such operating procedures and instructions within the *market rules*.

3.2.4 [Intentionally left blank – section deleted]

Identification of Reliability Standards

3.2.5 The *IESO* shall maintain a mapping containing *reliability standards* applicable to each class of *market participants,* as per the applicability criteria, and provide *market participants* with the ability to retrieve those *reliability standards'* obligations or requirements that the *IESO* determines apply to that *market participant*. The *IESO* may revise its applicability determination under this section at any time on notice to the *market participant*. If required, the *IESO* shall consult with *market participants* to finalize *reliability standards'* obligations or requirements that apply to a *market participant.*

3.2.6 The *IESO* shall inform *market participants* when an amendment to a *reliability standard* or a new *reliability standard* will come into effect in Ontario, and update the mapping containing *reliability standards* applicable to each class of *market participants* to provide *market participants* with the ability to retrieve the new or amended *reliability standards'* obligations or requirements that the *IESO* determines apply to that *market participant*. The *IESO* may revise its applicability determination under this section at any time on notice to the *market participant*.

3.2.7 A *market participant* may request the *IESO* review a determination under section 3.2.5 or 3.2.6 with respect to that *market participant*. The *IESO* shall, following consideration of any representations made by the *market participant*, determine whether the *reliability standards'* obligations or requirements apply to that *market participant*.

3.2A Technical Feasibility Exceptions

3.2A.1 The *IESO* may:

3.2A.1.1 reject or accept a *TFE application* in whole or in part;

3.2A.1.2 approve a *TFE application*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate or disapprove a *TFE application*, in whole or in part;

3.2A.1.3 upon the request of a *market participant* amend or transfer a *TFE*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate; or

3.2A.1.4 terminate or amend an approved *TFE*, in whole or in part, subject to any terms and conditions the *IESO* determines appropriate.

3.2A.2 A *TFE applicant* may, in accordance with the applicable *market manual*, request the *IESO* approve, amend, transfer, or terminate one or more *TFEs* by filing with the *IESO* a *TFE application* for each required *TFE*, and shall, in accordance with the applicable *market manual* submit to the *IESO* an initial deposit. A *TFE applicant* may withdraw a *TFE application* at any time.

3.2A.3 Upon request by the *IESO*, a *TFE applicant* shall provide to the *IESO*:

3.2A.3.1 a substantive review deposit amount;

3.2A.3.2 any supporting documentation; and

3.2A.3.3 an executed agreement pursuant to which the *TFE applicant* agrees to pay to the *IESO* an amount equal to all of the reasonable costs incurred by the *IESO* in processing the *TFE application* and maintaining an approved *TFE* until such time as the *TFE* is no longer in effect.

3.2A.4 The *IESO* shall process a *TFE application* in accordance with Ontario-adapted *NERC* procedures for processing *TFE applications* as set out in the applicable *market manual*.

3.2A.5 Where applicable, for each *TFE application*, the *IESO* shall establish a cost threshold or subsequent cost thresholds which it considers to be reasonable and which will form part of the executed agreement set out in section 3.2A.3.3 and will monitor expenditures against the processing costs of a *TFE application* and where that threshold is reached:

3.2A.5.1 the *IESO* shall advise the *TFE applicant* of the work and costs incurred to date;

3.2A.5.2 the *IESO* shall provide an estimate to the *TFE applicant* of the further work and costs necessary to complete the processing of the *TFE application*; and

3.2A.5.3 the *TFE applicant* may choose to continue with the processing of the *TFE application* or discontinue the processing of the *TFE application*. In the event that the *TFE applicant* chooses to discontinue the processing by withdrawing the *TFE application*, the *IESO* shall issue an *invoice* to the *TFE applicant* for the reasonable costs incurred by the *IESO* to that point.

3.2A.6 The *IESO* may utilize an independent third party to review a *TFE application* submitted by a *TFE applicant*.

3.2A.7 The *IESO* may consult with *NERC* or *NPCC* in its assessment of a *TFE application*.

3.2A.8 A failure by a *market participant* or the *IESO* to meet any of the terms and conditions of an approved *TFE* shall be a breach of the *market rules* and the *IESO* may terminate the approved *TFE* and require the *TFE applicant* to become compliant with the applicable *NERC reliability standard*.

3.2A.9 Subject to section 3.2A.4, all *TFE*s which remain in effect are subject to periodic review, in accordance with the applicable *market manual*, to verify continuing justification for the *TFE*.

3.2A.10 The *IESO* shall submit an *invoice* to a *TFE applicant* upon completion of the processing of that applicant's *TFE application* in an amount equal to all of the *IESO's* costs and expenses up to the point of deciding whether to approve or disapprove the *FTE*. The *IESO* may thereafter, from time to time, submit further invoices to the *TFE applicant* for costs and expenses for maintaining the approved *TFE* until such time as the *TFE* is no longer in effect, less in each case, the amount of any deposit paid pursuant to section 3.2A.3.1 not previously applied against the *IESO's* costs and expenses.

3.2A.11 A *TFE applicant* shall, within thirty days of the date of an *invoice* referred to in section 3.2A.5.3 or 3.2A.10, pay to the *IESO* the amount owing.

3.2B Bulk Electric System Exceptions

3.2B.1 A *BES exception applicant* may, in accordance with the applicable *market manual*, request the *IESO* approve, amend, transfer, or terminate one or more *BES exceptions* by filing with the *IESO* a *BES exception request* for each required *BES exception*, and shall, in accordance with the applicable *market manual* submit to the *IESO* an initial deposit. A *BES exception applicant* may withdraw a *BES exception request* at any time.

3.2B.2 The *IESO* may review, reject or accept a *BES exception request* in whole or in part.

3.2B.3 The *IESO* shall process a *BES exception request* in accordance with the Ontario-adapted *NERC* procedure for processing *BES exception requests* as set out in the applicable *market manual*.

3.2B.4 Upon request by the *IESO*, a *BES exception applicant* shall provide to the *IESO*:

3.2B.4.1 a substantive review deposit amount;

3.2B.4.2 any supporting documentation; and

3.2B.4.3 an executed agreement pursuant to which the *BES exception applicant* agrees to pay to the *IESO* an amount equal to all of the reasonable costs incurred by the *IESO* in processing the *BES exception request*.

3.2B.5 Where applicable, for each *BES exception request*, the *IESO* shall establish a cost threshold or subsequent cost thresholds which it considers to be reasonable and which will form part of the executed agreement set out in section 3.2B.4.3 and will monitor expenditures against the processing costs of a *BES exception request* and where that threshold is reached:

3.2B.5.1 the *IESO* shall advise the *BES exception applicant* of the work and costs incurred to date;

3.2B.5.2 the *IESO* shall provide an estimate to the *BES exception applicant* of the further work and costs necessary to complete the processing of the *BES exception request*; and

3.2B.5.3 the *BES exception applicant* may choose to continue with the processing of the *BES exception request* or discontinue the processing of the *BES exception request*. In the event that the *BES exception applicant* chooses to discontinue the processing by withdrawing the *BES exception request*, the *IESO* shall issue an *invoice* to the *BES exception applicant* for the reasonable costs incurred by the *IESO* to that point.

3.2B.6 The *IESO* may utilize an independent third party to review a *BES exception request* submitted by a *BES exception applicant*.

3.2B.7 After receiving a recommendation from the *IESO* on a *BES exception request*, the *IESO Board* or a panel of the *IESO Board* as determined by the Chair of the *IESO Board* may:

3.2B.7.2 approve or disapprove a *BES exception request*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate or disapprove a *BES exception request*, in whole or in part;

3.2B.7.3 upon the request of a *market participant* or a *connection applicant* amend or transfer a *BES exception*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate; or

3.2B.7.4 terminate or amend an approved *BES exception*, in whole or in part, subject to any terms and conditions the *IESO* determines appropriate.

3.2B.8 A failure by a *market participant* or the *IESO* to meet any of the terms and conditions of an approved *BES exception* shall be a breach of the *market rules* and the *IESO Board* or a panel of the *IESO Board* as determined by the Chair of the *IESO Board* may terminate the approved *BES exception* and require the *BES exception applicant* to become compliant with the applicable *NERC reliability standards.*

3.2B.9 All *BES exceptions* are subject to periodic review, in accordance with the applicable *market manu*al, to verify continuing justification for the *BES exception* and may be referred to the *IESO Board* or a panel of the *IESO Board* as determined by the Chair of the *IESO Board* in accordance with section 3.2B.1.4.

3.2B.10 The *IESO* shall submit an *invoice* to a *BES exception applicant* upon completion of the processing of that applicant's *BES exception request* in an amount equal to all of the *IESO's* costs and expenses relating to the processing of the *BES exception applicant's BES exception request* less the amount of any deposit paid pursuant to section 3.2B.3.1.

3.2B.11 A *BES exception applicant* shall, within thirty days of the date of an *invoice* referred to in section 3.2B.5.3 or 3.2B.10, pay to the *IESO* the amount owing.

3.3 Reliability-Related Information

3.3.1 Within 90 days after the date of coming into force of this Chapter, the *IESO* shall *publish* a list of the categories of *reliability*-related information that it shall make available to *market participants*, the time periods within which such information will be provided, and the manner in which such information will be provided. Such information shall include, but not be limited to, information designed to:

3.3.1.1 enable *market participants* to initiate procedures to manage the potential risk of any action taken by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*;

3.3.1.2 assist *market participants* in meeting their obligations under this Chapter; and

3.3.1.3 notify *market participants* of any operating changes or decisions that may have an impact on their operations, *facilities* or equipment.

3.3.2 Within 90 days after the date of coming into force of this Chapter, the *IESO* shall publish a catalogue of the *reliability*-related information that the *IESO* shall require be provided to it by *market participants*, including the information referred to in section 14.1.3, the time periods within which such information will be provided and the manner in which such information will be provided. At the same time, the *IESO* shall *publish* initial monitoring indices that the *IESO* shall use in evaluating the information so provided.

3.3.3 *Market participants* shall provide the *IESO* with the information referred to in section 3.3.2 within the time and in the manner required.

3.3.4 Subject to the confidentiality provisions of Chapters 3 and 4, the *IESO* shall, if requested to do so by a *market participant*, provide to that *market participant reliability*-related information not contained in the list referred to in section 3.3.1, provided that the *IESO* shall be under no obligation to provide any information that, in the *IESO's* opinion, would provide the requesting *market participant* with an undue advantage in the *IESO-administered markets*. In order to prevent any such undue advantage, the *IESO* may provide *market participants* with notice of the request prior to providing such information and may make the information requested by a *market participant* simultaneously available to all *market participants*.

3.4 Obligations of Transmitters

3.4.1 Each *transmitter* shall operate and maintain its transmission *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.4.1.1 ensuring that systems and procedures for load-shedding in *emergencies* are provided for as specified in section 10;

3.4.1.2 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated, rotational load-shedding and restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.4.1.3 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment;

3.4.1.4 promptly informing the *IESO* of any change or anticipated change in the capability of its transmission *facilities* or the status of its equipment or *facilities* forming part of the *IESO-controlled grid*, and of any other change or anticipated change in its transmission *facilities* that could have a material effect on the *reliability* of the *IESO-controlled grid* or the operation of the *IESO-administered markets;* and

3.4.1.5 promptly complying with the *IESO's* directions, including directions to *disconnect facilities* or equipment from the *IESO-controlled grid* or its *transmission system* for *reliability* purposes, unless the *transmitter* reasonably believes that following the *IESO's* direction poses a real and substantial risk of damage to its equipment, to the safety of its employees or the public, or of undue injury to the environment. In all cases where the *transmitter* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above.

3.4.2 Each *transmitter* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards*, subject to the information reporting requirements specified in section 14.1.2.

3.5 Obligations of Wholesale Customers

3.5.1 Each *connected wholesale customer* shall operate and maintain its *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.5.1.1 ensuring there are controls, monitoring, and secure communication systems to facilitate a manually initiated, rotational load-shedding and restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.5.1.2 promptly informing the *IESO* of any change or anticipated change in the status of any *facility* or equipment that it operates and that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated change in its *facilities* or equipment that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets;*

3.5.1.3 promptly complying with the *IESO's* directions, including directions to disconnect equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *connected wholesale customer* reasonably believes that following the *IESO's* direction poses a real and substantial risk of damage to its *equipment*, to the safety of its employee or the public, or of undue injury to the environment. In all cases where the *connected wholesale customer* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above; and

3.5.1.4 [Intentionally left blank]

3.5.1.5 providing, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

a. the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* that it operates, where such *planned outage*, closure, test or other similar operational event is expected to result in a change in *demand* of 20 MW or more; relative to the average weekday demand of that *facility*; and

b. the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* that it operates and that has been specifically designated by the *IESO* for this purpose.

3.5.2 Each *wholesale consumer* that is an *embedded market participant* and that operates a *registered facility* that is not directly *connected* to the *IESO-controlled grid* shall provide, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

3.5.2.1 the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any such *registered facility*, where such *planned outage*, closure, test or other similar operational event is expected to result in a change in *demand* of 20 MW or more relative to the average weekday demand of that *registered facility*; and

3.5.2.2 the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of such *registered facility* that has been specifically designated by the *IESO* for this purpose.

3.5.3 Each *wholesale customer* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards*, subject to the information reporting requirements specified in section 14.1.2.

3.6 Obligations of Generators (Embedded and Non-embedded)

3.6.1 Each *generator* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall operate and maintain its *generation facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities related to *reliability*. Such obligation shall include, but not be limited to, the following:

3.6.1.1 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.6.1.2 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment, as required by the *IESO* to *reliably* operate the *IESO-controlled grid*;

3.6.1.3 promptly informing the *IESO* of any change or anticipated change in the status of any *generation facility* or related equipment that it operates and that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated change in its *generation facilities* or equipment that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets.* Such change shall include, but not be limited to, any change in status that could affect the maximum output of a *generation unit*, the minimum load of a *generation unit*, the ability of a *generation unit* to operate with *automatic voltage regulation*, or the availability of a *generation unit* to provide *ancillary services* (unless no application has been made to provide *ancillary services* to the *IESO-administered markets* in respect of a given *generation unit);*

3.6.1.4 promptly informing the *IESO* if any of the *generation facilities* that it operates are unable for any reason to operate in accordance with the schedules determined pursuant to Chapter 7;

3.6.1.5 providing the *IESO* with current information showing the maximum unit capabilities of each of its *generation units* to facilitate *dispatch* in an *emergency operating state*. Such maximum unit capabilities shall consist of the maximum physical-rating of the *generation unit* and shall not be limited to the unit capabilities contained in the *offers* submitted for such *generation unit* pursuant to Chapter 7;

3.6.1.6 promptly complying with the *IESO's* directions, including directions to disconnect equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *generator* reasonably believes that following the *IESO's* direction poses a real and substantial risk of damage to its equipment, to the safety of its employee or the public, or of undue injury to the environment. In all cases where the *generator* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above; and

3.6.1.7 [Intentionally left blank]

3.6.2 Each *generator* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards*, subject to the information reporting requirements specified in section 14.1.2.

3.7 Obligations of Distributors

3.7.1 Each *distributor* shall operate and maintain its distribution *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.7.1.1 ensuring that systems and procedures for load-shedding in *emergencies* are provided for as specified in section 10;

3.7.1.2 promptly informing the *IESO* of any change or anticipated change in the capability of its equipment or distribution *facilities* connected to the *IESO-controlled grid* that could have a material effect on the *reliable* operation of the *IESO-controlled grid* or the operation of the *IESO-administered markets*;

3.7.1.3 promptly informing the *IESO* of any event or circumstance in its service territory that could have a material effect on the *reliability* of the *IESO-controlled grid;*

3.7.1.4 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for equipment and distribution *facilities* that are included within the *IESO-controlled grid*;

3.7.1.5 promptly complying with the *IESO's* directions, including directions to *disconnect facilities* or equipment from the *IESO-controlled grid* or its *distribution system* for *reliability* purposes, unless the *distributor* reasonably believes that following the *IESO's* direction poses a real and substantial risk of damage to its equipment, to the safety of its employee or the public, or of undue injury to the environment. In all cases where the *distributor* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above;

3.7.1.6 providing, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

a. the timing and duration of any *planned outage*, closure, test or other event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* which is not a *registered facility* that draws electrical *energy* from or injects electrical *energy* into its *distribution system*, where such *planned outage*, closure, test or other event is expected to result in a change in *demand* or supply by that *facility* of 20 MW or more relative to the average weekday demand or supply of that *facility*; and

b. the timing and duration of any *planned outage*, closure, test or other event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* which is not a *registered facility* that draws electrical *energy* from or injects electrical *energy* into its *distribution system* and that has been specifically designated by the *IESO* for this purpose, where such *planned outage*, closure, test or other event is expected to result in a change in *demand* or supply by such *facility* relative to the average weekday *demand* or supply of that *facility*; and

3.7.1.7 [Intentionally left blank]

3.7.2 Each *distributor* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards*, subject to the information reporting requirements specified in section 14.1.2.

4. System Reliability

4.1 Objectives

4.1.1 The objective of this section 4 is to set forth the requirements to ensure the availability of sufficient *generation capacity* and *ancillary services* to the *IESO-administered markets.*

4.2 Standards for Ancillary Services

4.2.1 The *IESO* shall operate the *IESO-administered markets* and contract for *ancillary services*, including by means or within the scope of an *operating agreement* or another agreement of similar nature, to ensure that sufficient *ancillary services* are available to ensure the *reliability* of the *IESO-controlled grid*. *Ancillary services* shall be procured by the *IESO* in accordance with this Chapter and Chapter 7.

4.2.2 The requirements for *ancillary services* shall be determined based on all applicable *reliability standards* and actual and expected conditions on the *IESO-controlled grid.* Requirements for *ancillary services* may be adjusted from time to time by the *IESO* to take into account, among other things, variations in *integrated power system* conditions, real-time *dispatch* constraints, *contingency events*, the prevailing level of system risks or vulnerability, and the results of assessments of the voltage and dynamic stability of the *integrated power system*.

4.2.3 The *IESO* shall, in accordance with the procedures set forth in section 4 of Chapter 3, periodically review the operation of the *IESO-administered markets* for *ancillary services* to determine whether any revision to the requirements and standards for *ancillary services* is required for *reliability* purposes. As a minimum, the *IESO* shall conduct such reviews to accommodate revisions to applicable criteria established by relevant *standards authorities*.

4.3 Generic Performance Requirements for Ancillary Services

4.3.1 *Ancillary services* may be provided to the *IESO* only by *registered facilities* as required by Chapter 7. *Ancillary services* may be offered to the *IESO* in its daily and hourly *physical markets* or provided to the *IESO* under *contracted ancillary service* contracts through the *IESO's ancillary services procurement markets* or by means or within the scope of *operating agreements* or another agreement of a similar nature. Prior to entering into a contract with any *ancillary service provider*, the *IESO* shall determine whether the *facilities* and procedures of such *ancillary service provider* meet the requirements for registration as a *registered facility* in respect of the *ancillary service(s)* to be provided and are otherwise in compliance with the technical requirements of this Chapter. The *IESO* shall not contract for *ancillary services* with an *ancillary services provider* whose *facilities* are not in compliance with such requirements.

4.3.2 In order to make the determination referred to in section 4.3.1, the *IESO* may require each *ancillary service provider* to demonstrate through physical tests or other appropriate means specified by the *IESO* that the *registered facilities* or equipment that will be used to provide the *ancillary service* meet the performance standards for each *ancillary service* set forth in Appendix 5.1 or in the applicable *market manual*.

4.3.3 [Intentionally left blank – section deleted]

4.3.4 [Intentionally left blank – section deleted]

4.4 Regulation

4.4.1 The *IESO* shall maintain sufficient *regulation* to allow the *IESO* to meet all applicable *reliability standards.*

4.4.2 The *IESO* shall determine the quantity of *regulation* capacity needed for each hour of the following day. As a minimum, the requirement shall be +/- 100 MW, with a ramp rate of 50 MW/min.

4.4.3 If the *IESO* is unable to comply with applicable *reliability standards,* it shall take corrective action to achieve compliance with applicable *reliability standards* within three months.

4.4.4 *Area control error (ACE)* shall be calculated by the *IESO* in accordance with section 4.4.5 and all applicable *reliability standards*. Control signals shall be sent from the *IESO* to *registered facilities* providing *regulation*, as required by the *IESO*.

4.4.5 The calculation of *ACE* shall occur at least every four seconds.

4.4A Assistance to Other Control Areas

4.4A.1 Notwithstanding any other provision of the *market rules*, when a *transmission system* in another *control area* is in a state identical or comparable to an *emergency operating state*, the *IESO* may, in accordance with all applicable *reliability standards* and any applicable *interconnection agreement*, provide *emergency energy* to the *control area* within which such other *transmission system* is located in order to maintain the *reliability* of such *transmission system.* The *IESO* shall only provide *emergency energy* to another *control area* in circumstances where *energy* could not be obtained by that *control area* using the *offer* and *bid* processes described in Chapter 7. The compensation associated with the provision of such *emergency energy* that is received by the *IESO* pursuant to the applicable *interconnection agreement* shall be distributed in accordance with section 4.8 of Chapter 9.

4.5 Operating Reserve

4.5.1 *Operating reserve* is capacity that, for any given operating interval or *dispatch interval*, is in excess to that required to meet anticipated requirements for *energy* for that operating interval or dispatch interval, and is available to the *integrated power system* for *dispatch* by the *IESO* within a specified time period, such as 10 minutes or 30 minutes. *Operating reserves* may be provided by *generation facilities, dispatchable loads* and *boundary entities* to the extent that each meets the applicable requirements to be a *registered facility* in respect of each category of *operating reserves*. Neighbouring *control areas* may also provide *operating reserve* through simultaneous activation of *operating reserve* and regional reserve sharing programs. *Operating reserve* is required to:

4.5.1.1 cover or offset unanticipated increases in load during a *dispatch day* or *dispatch hour*;

4.5.1.2 replace or offset capacity lost due to the *forced outage* of generation or transmission equipment; or

4.5.1.3 cover uncertainty associated with the performance of *generation facilities* or *dispatchable loads* in responding to the *IESO's dispatch instructions*.

4.5.2 The *IESO* shall maintain sufficient *operating reserve* to meet all applicable *reliability standards.*

4.5.3 The *IESO* shall maintain, as a minimum, total *operating reserve* that is the sum of the *ten-minute operating reserve* requirement and the *thirty-minute operating reserve* requirement.

4.5.4 Part of the requirement for *ten-minute operating reserve* shall be synchronized with the *IESO-controlled grid* consistent with section 4.5.9.

4.5.5 The *IESO* shall ensure that *operating reserve* is distributed throughout the *IESO-controlled grid* such that sufficient *operating reserve* can be activated and delivered to any location on the *integrated power system*.

Simultaneous Activation of Reserve

4.5.6 The *IESO* may simultaneously activate with nearby systems in *NPCC* and *PJM* its *ten-minute operating reserve* to respond to *contingency events* in accordance with agreements between the *IESO* and such systems. Similarly, such systems may activate their *operating reserve* when requested to meet *contingency events* in the *IESO control area* in accordance with agreements between the *IESO* and such systems. Such simultaneous activation of *operating reserve* is solely for the purpose of maintaining the *reliability* of *interconnection systems* and shall not alter the *operating reserve* requirements of the *IESO*.

Control Action Operating Reserve

4.5.6A The *IESO* may include voltage reductions, and reductions in the *thirty-minute operating reserve* requirements within allowable *reliability standards* as standing *offers* in the *operating reserve markets* subject to the following conditions:

4.5.6A.1 the *IESO* shall introduce such standing *offers* in increasing quantities;

4.5.6A.2 the quantities referred to in section 4.5.6A.1 and the prices therefore shall be determined by the *IESO Board* and such quantities and prices shall be *published* by the *IESO*;

4.5.6A.3 the *IESO Board* may specify the circumstances under which any one or more of the quantities may either be withdrawn or not introduced and the manner in which any such withdrawal will be effected and the *publishing* thereof;

4.5.6A.4 the *IESO* shall *publish* the times and quantities of the voltage reductions and reduction in *thirty-minute operating reserve* when these sources of *operating reserve* have been scheduled to provide *operating reserve;* and

4.5.6A.5 the prices and quantities of the standing *offers* set by the *IESO Board* in accordance with section 4.5.6A.2 shall be monitored by the *IESO* to assess their impacts and that any changes to the prices and quantities would be recommended to the *IESO Board* as necessary.

Regional Reserve Sharing

4.5.6B The *IESO* may participate in regional reserve sharing programs with neighbouring *control areas*. Subject to availability and deliverability of the associated energy, the *IESO* may count towards its *ten-minute operating reserve* requirement a contribution of up to 100 MW from neighbouring *control areas* in accordance with applicable regional reserve sharing programs and applicable *reliability standards.* The *IESO* shall activate *energy* from regional reserve sharing programs in accordance with applicable *reliability standards*.

Ten-Minute Operating Reserve

4.5.7 *Ten-minute operating reserve* is capacity that is available to the *integrated power system* in excess of anticipated requirements for *energy* and that can be made available and used within ten minutes. It includes resources that are either synchronized or non-synchronized with the *IESO-controlled grid*.

4.5.8 The *IESO* shall maintain sufficient *ten-minute operating reserve* to meet the requirements of all applicable *reliability standards.* This shall be at least equal to the largest first contingency loss sustainable on the *IESO-controlled grid*.

4.5.9 *Ten-minute operating reserve* shall be synchronized with the *IESO-controlled grid* to the extent required by all applicable *reliability standards*.

4.5.10 If, for any reason, there is a deficiency of *ten-minute operating reserve,* the *IESO* shall replace such *reserve* in accordance with the applicable *reliability standards* referenced in the *market manuals*.

4.5.11 The *IESO* shall, in accordance with Chapter 7, *publish* daily its estimates of the quantity of *ten-minute operating reserve* that is required for each hour of the following day.

4.5.12 A *registered facility* that is a *boundary entity* that is used as *ten-minute operating reserve* shall be treated as *operating reserve* that is non-synchronized with the *IESO-controlled grid*.

4.5.13 The reduction in load that can be effected by curtailing pumping hydroelectric *generation facilities* is eligible to be treated as *operating reserve* that is synchronized with the *IESO-controlled grid*.

4.5.13A [Intentionally left blank – section deleted]

4.5.14 [Intentionally left blank]

4.5.15 [Intentionally left blank]

4.5.16 [Intentionally left blank]

4.5.17 [Intentionally left blank]

Thirty-Minute Operating Reserve

4.5.18 *Thirty-minute operating reserve* is capacity in excess of anticipated requirements for *energy* that can be made available and used within thirty-minutes and that is not included as *ten-minute operating reserve*.

4.5.19 Subject to section 4.5.20, the requirement for *thirty-minute operating reserve* shall be one-half of the largest *second contingency loss* sustainable on the *IESO-controlled grid*. However, when a *generation unit* is commissioning and is one of the two largest *contingency events*, the requirement for *thirty-minute operating reserve* shall equal the *second contingency loss*.

4.5.20 If such a commissioning *generation unit* is not one of the two largest *contingency events*, the requirement for *thirty-minute operating reserve* shall be the larger of one-half of the *second contingency loss* or the output of the commissioning *generation unit.*

4.5.21 The requirement for *thirty-minute operating reserve* shall be maintained in accordance with the applicable *reliability standards* referenced in *the market manuals*.

4.6 Reactive Support and Voltage Control

4.6.1 *Reactive support service and voltage control service* is the control and maintenance of prescribed voltages on the *IESO-controlled grid*. The devices that supply reactive power to the *integrated power system* include but are not limited to, capacitors, static VAR compensators, reactors, synchronous *generation facilities*, and synchronous condensers.

4.6.1A The *IESO* shall direct the operation of the *IESO-controlled grid* to meet all applicable *reliability standards* with respect to the *dispatch* of reactive power resources.

4.6.2 The *IESO* shall ensure that sufficient resources are available throughout the *IESO-controlled grid* to meet all applicable *reliability standards* for *reactive support service and voltage control service*. Voltage levels shall be maintained within acceptable levels within the *IESO-controlled grid*. As part of its assessment of system *adequacy* under the *market rules*, the *IESO* shall on a continual basis assess whether sufficient reactive resources are available to the *IESO*.

4.6.3 The *IESO* shall direct providers of *reactive support service and voltage control service* to take any actions necessary to maintain stable voltage levels in accordance with *reliability standards* and to prevent the collapse of voltages on the *IESO-controlled grid*.

4.6.4 [Intentionally left blank]

4.6.5 [Intentionally left blank]

4.6.6 [Intentionally left blank]

4.6.7 [Intentionally left blank]

4.6.8 [Intentionally left blank]

4.6.9 The *IESO* shall obtain reactive power resources to maintain *reactive support service* and *voltage control service* in accordance with all applicable *reliability standards*. *Reactive support service* and *voltage control service* shall be made available by *market participants* from, but not limited to, the following:

4.6.9.1 reactive resources produced from within the standard power factor range of a *generation facility* as described in Chapter 4, which shall be *dispatchable* by the *IESO*;

4.6.9.2 equipment owned by *market participants* (capacitors, SVCs, synchronous condensers and reactors) that is made available to the *IESO* pursuant to the *market rules* and any *operating agreement* between the *IESO* and a *market participant*; and

4.6.9.3 reactive resources produced outside the standard power factor range of a *generation facility* as required in Chapter 4 of the *market rules* (synchronous condensers or hydroelectric units in condense mode) as acquired by the *IESO* through *contracted ancillary services* contracts.

4.7 Black Start Service

4.7.1 [Intentionally left blank]

4.7.2 The *IESO* shall determine the required amounts and locations of *black start capability* across the *IESO-controlled grid*, as required to satisfy the requirements of the *Ontario power system restoration plan* and all applicable *reliability standards.* The *IESO* shall notify *market participants* of these requirements before entering into agreements for the provision of *certified black start facilities*.

4.7.3 *Ancillary service providers* providing *certified black start facilities* must also be *restoration participants*.

4.8 Reliability Must-Run Resources

4.8.1 The *IESO* may need to call on specific *registered facilities*, excluding *non-dispatchable load facilities,* to maintain the *reliability* of the *IESO-controlled grid* whenever sufficient resources for the provision of *physical services*, other than *contracted ancillary services*, are not otherwise offered in the *IESO-administered markets*. Such applicable *registered facilities* are referred to as *reliability must-run resources* and shall be procured either through *reliability must-run contracts* in accordance with this section 4.8 and sections 9.6 and 9.7 of Chapter 7 or by means of the process for directing the submission of *dispatch data* referred to in sections 3.3.10 to 3.3.17 of Chapter 7.

4.8.2 The *IESO* shall identify all *reliability must-run resources* in respect of which it wishes to conclude *reliability must-run contracts* and may enter into *reliability must-run contracts* with the *registered market participant* or prospective *registered market participant* for such *reliability must-run resources*. Where the *IESO* identifies such a *reliability must-run resource*, the *registered market participant* or prospective *registered market participant* for such *reliability must-run resource* shall, subject to section 9.6.4 of chapter 7, contract with the *IESO* to supply *physical services,* other than *contracted ancillary services*, to the *IESO-controlled grid* for *reliability* purposes in accordance with sections 9.6 and 9.7 of Chapter 7. Each such *reliability must-run contract* shall provide the *IESO* with the ability to call on the *reliability must-run resources* covered by the *reliability must-run contract* in accordance with section 9 of Chapter 7 and shall comply with Chapter 7.

4.8.3 [Intentionally left blank]

4.8.4 The provisions of this section 4.8 and of any *reliability must-run contracts* shall be consistent with the provisions of the *license* of the *IESO* that incorporate the terms of any directive issued by the *Minister* to the *Ontario Energy Board* pursuant to subsection 28(1) of the *Ontario Energy Board Act, 1998* or that incorporate terms imposed by the *Ontario Energy Board* in furtherance of the exercise of its powers under subsection 70(5) of the *Ontario Energy Board Act, 1998*. In the event of any inconsistency between such terms and the provisions of this section 4.8 or of any *reliability must-run contracts,* such terms shall govern.

4.8A [Intentionally left blank – section deleted]

4.8A.1 [Intentionally left blank – section deleted]

4.8A.2 [Intentionally left blank – section deleted]

4.9 Auditing and Testing of Ancillary Services

4.9.1 The *IESO* shall test *facilities* that will or do provide *ancillary services* to the *IESO-controlled grid.* The *IESO* shall use such tests to determine whether to register each *facility* as a *registered facility* for the provision of *ancillary services* and to ensure that each applicable *registered facility* continues to meet the requirements for registration to provide the relevant *ancillary services.*

4.9.1.1 [Intentionally left blank]

4.9.1.2 [Intentionally left blank]

4.9.2 Tests of the *facilities* or *registered facilities* of *ancillary service providers* or of prospective *ancillary service providers* referred to in section 4.9.1 shall include, but not be limited to, testing in the manner set forth in this section 4.9.2, to determine whether the *ancillary service provider* can supply the *ancillary services* which it wishes to supply or has contracted or been registered to supply:

4.9.2.1 the *IESO* may test the synchronized *ten-minute operating reserve* capability of a *generation facility* by issuing unannounced *dispatch instructions* requiring the *generation facility* to ramp up to its ten-minute capability;

4.9.2.2 the *IESO* may test the non-synchronized *ten-minute operating reserve* capability of a *generation facility* or *dispatchable load* by issuing unannounced *dispatch instructions* requiring the *generation facility* or *dispatchable load* to come on line and ramp up or to reduce *demand*, in either case to its ten-minute capability;

4.9.2.3 the *IESO* may test the *thirty-minute operating reserve* capability of a *generation facility* or *dispatchable load* by issuing unannounced *dispatch instructions* requiring the *generation facility* or *dispatchable load* to come on line and ramp up or to reduce *demand*, in either case to its thirty-minute capability;

4.9.2.4 a *certified black start facility* must perform tests on auxiliary and control equipment and alternate sources of power in accordance with and using the testing criteria and testing frequency requirements specified in the *Ontario power system restoration plan*;

4.9.2.4A a *certified black start facility* must pass the tests required for *certified black start facilities* in accordance with and using the testing criteria specified in the *Ontario power system restoration plan*;

4.9.2.4B the *IESO* may direct line energization tests of a *certified black start facility* to determine whether the *certified black start facility* can energize a transmission path specified by the *IESO*;

4.9.2.5 the *IESO* may test the *reactive support and voltage control* that has been contracted from a *registered facility* that is a *generation facility* by issuing unannounced *dispatch instructions* requiring the *generation facility* to provide such support within its contracted capability; and

4.9.2.6 the *IESO* shall at least annually test a *registered facility* providing *regulation* for compliance with the performance standards referred to in sections 1.1.3 and 1.1.4 of Appendix 5.1 in accordance with the testing procedures specified in the applicable *contracted ancillary services* contract.

4.9.3 The costs incurred by the *IESO* in conducting and evaluating any tests pursuant to section 4.9.1 or 4.9.2 shall be recovered by the *IESO* as part of the costs to the

IESO of contracting for the applicable *ancillary service* in accordance with section 4.2 of Chapter 9.

4.9.4 Any costs incurred by the *ancillary service provider* in conducting any tests pursuant to section 4.9.1 or 4.9.2 shall be borne by the *ancillary service provider*.

4.10 Consequences of Failure to Pass a Test

4.10.1 If an *ancillary service provider's registered facility* fails a test performed pursuant to section 4.9.1 or 4.9.2 in respect of an *ancillary service*, the *IESO* shall not schedule such *ancillary services* from such *registered facility* until the *ancillary service provider* demonstrates that it can provide the relevant *ancillary service*.

4.10.2 Without prejudice to the application of section 4.10.1, an *ancillary service provider* whose *registered facility* fails a test performed pursuant to section 4.9.1 or 4.9.2:

4.10.2.1 in the case of an *ancillary service provider* providing a *certified black start facility* or *regulation* under a *contracted ancillary service* contract:

a. where there is sufficient information available to determine the date as of which the applicable *contracted ancillary service* was not provided, the *IESO* may require the *ancillary service provider* to refund the compensation it has received for such *contracted ancillary service* from such date to the date of the failed test; or

b. in all other cases, the *ancillary service provider* shall provide such refund of compensation, if any, as may be specified in its *contracted ancillary service* contract;

4.10.2.2 in the case of an *ancillary service provider* providing a *certified black start facility* or *regulation* under a *contracted ancillary service* contract, shall be subject to such penalties and sanctions as may be specified in its *contracted ancillary service* contract; and

4.10.2.3 in the case of any other *ancillary service provider*, shall be subject to financial penalties in accordance with section 6.6 of Chapter 3 and to such other sanctions as may be provided for in these *market rules*.

4.11 Emergency Conditions

4.11.1 Notwithstanding any other provision of the *market rules*, when the *IESO-controlled grid* is in an *emergency operating state*, the *IESO* may acquire *ancillary services* from any *market participant*, whether or not such *market participant* satisfies all of the standards and registration requirements applicable in respect of such *ancillary services*.

5. System Security

5.1 Objectives and General Obligations

5.1.1 The objective of this section is to detail the procedures necessary to enable the *IESO* to ensure the *security* of the *IESO-controlled grid* in accordance with all applicable *reliability standards.*

5.1.2 In order to maintain the *security* of the *IESO-controlled grid*, the *IESO* shall:

5.1.2.1 monitor the real-time operating status of the *IESO-controlled grid*;

5.1.2.2 establish and *publish security limits* for all *facilities* that are part of the *IESO-controlled grid*;

5.1.2.3 establish and *publish* criteria and margins to be used in the development of *security limits* and a process for reviewing and revising such criteria and margins;

5.1.2.4 establish available *transmission transfer capabilities* in accordance with all applicable *reliability standards* and manage the use of transmission in accordance with such *transmission transfer capabilities* and the *market rules*;

5.1.2.5 direct the operation of *facilities* that are part of the *IESO-controlled grid* within the appropriate *security limits* and in accordance with the applicable *operating agreements*;

5.1.2.6 direct any *market participant* to take or to refrain from taking any action necessary to maintain the *IESO-controlled grid* in a *normal operating state*;

5.1.2.7 act as the *control area operator* and as *security coordinator* for the province of Ontario and interact with other *control area operators*, *security coordinators* and *interconnected transmitters* as required to establish *security limits* and rules for interconnected operations including, but not limited to, entering into *interconnection agreements* with adjacent *control area operators*, *security coordinators* and *interconnected transmitters* that provide for interconnected operations, other than with respect to the physical *facility* and equipment requirements for *interconnections* which shall be the responsibility of *transmitters*. In the event of flows or exchanges of *physical services* across the *interconnections* or *interties* which are not directly attributable to the transactions of *market participants*, the *IESO* may provide for such exchanges through the sale or purchase of these *physical services* in the *IESO-administered markets*;

5.1.2.8 represent Ontario in the context of the work of *standards authorities* with respect to the *reliable* operation of the *IESO-controlled grid* and the *interconnected systems*, and the operation of the *IESO-administered markets*, other than with respect to the physical facility and equipment requirements for *reliability* of the *IESO-controlled grid* which shall be the responsibility of the relevant *transmitters*, *distributors* and *generators* as applicable;

5.1.2.9 investigate major operational incidents on the *IESO-controlled grid* and initiate plans to manage abnormal situations or significant deficiencies which, in the *IESO's* opinion, threaten the *reliability* of the *IESO-controlled grid*;

5.1.2.10 issue directions to market participants in order to manage high-risk operating states and emergency operating states; and

5.1.2.11 assess the future *reliability* of the *IESO-controlled grid*.

5.2 Security Limits

5.2.1 The *IESO* shall establish and *publish security limits* to prevent, contain and alleviate the effects of *contingency events*. Such *security limits* shall be as described in section 5.2.4 and shall be observed by the *IESO* in the minute-to-minute operation of the *IESO-controlled grid*.

5.2.2 The *IESO* shall calculate and *publish transmission transfer capabilities*.

5.2.3 *Market participants* shall immediately respond to directions from the *IESO* to alter their operations to stay within the *security limits* and *transmission transfer capabilities* established by the *IESO*.

5.2.4 Two types of *security limits* shall be established by the *IESO*:

5.2.4.1 *security limits* based on the dynamic response of the *IESO-controlled grid*, including transient stability limits, voltage stability limits, dynamic stability limits, and voltage decline limits; and

5.2.4.2 *security limits* based on the ratings of equipment, including the thermal ratings of lines and transmission equipment (e.g. the design characteristic of lines and equipment and weather conditions) and the short circuit capability of equipment.

5.2.5 Each *market participant* shall:

- establish thermal ratings for the equipment that it owns and that is part of the *IESO-controlled grid*, and
- provide such ratings (including continuous and limited time ratings) to the *IESO* in a form suitable for *IESO* monitoring

The *IESO* shall not deliberately operate or plan to operate equipment comprising the *IESO-controlled grid* in excess of the thermal rating for such equipment as communicated to the *IESO* by the relevant *market participants*.

5.2.6 The *IESO* shall respect all pre-and post-contingency *security* criteria that are used to establish *security limits*.

5.3 The Use of Tie-Lines and Associated Facilities

5.3.1 The *IESO-controlled grid* is interconnected with utilities in Canada and the United States via *tielines* such that *interconnected systems* can be used to help maintain the *security* of the *IESO-controlled grid*.

5.3.2 With respect to the use of *tielines*:

5.3.2.1 the *IESO* shall endeavour to conduct studies on a coordinated basis with adjacent *control areas* so that normal and emergency transfer limits on all *tielines* are established or reaffirmed at least annually;

5.3.2.2 the *IESO* shall endeavour to cooperate with other *control area operators* to determine and reaffirm total *transmission transfer capability* with other *control areas* at least annually;

5.3.2.3 the *IESO* shall operate the *IESO-controlled grid* so that there is no net transfer of reactive power, provided that reactive power may be exchanged or transferred from one system to another under contractual agreement with adjacent *control areas;*

5.3.2.4 the maximum net scheduled interchange across *tielines* shall not exceed the lower of the continuous rating of the *tielines* or the incremental transfer capability of the first *contingency event*;

5.3.2.5 for *interconnected systems* that are entirely controlled by phase-shifters, such as Manitoba and Minnesota, the *IESO* shall maintain MW flows at the scheduled transfer level;

5.3.2.6 unless there is prior agreement to that effect between *control areas*, the *IESO* shall not move phase shifters or make changes to fixed-tap positions; and

5.3.2.7 the *IESO* shall abide by all applicable *reliability standards* with respect to the management of *tielines*.

5.3.3 Each *market participant* shall comply with all relevant *reliability standards* relating to the *reliability* of *interconnections* and:

5.3.3.1 each *registered market participant* submitting an *energy offer* or an *energy bid* in respect of a *boundary entity* shall comply with the scheduling and notification procedures for the source or sink *control area*, as applicable, and any intervening *control areas* and with all other applicable procedural and information requirements established by relevant *standards authorities* and other relevant entities for registering transactions and/or arranging transmission access;

5.3.3.2 each *registered market participant* submitting an offer to provide *operating reserve* in respect of a *boundary entity* shall comply with all applicable procedural and information requirements established by relevant *standards authorities* and other relevant entities for registering transactions and/or arranging transmission access; and

5.3.3.3 the notification of the activation of the *energy* associated with an *operating reserve offer* and the scheduling coordination shall be the responsibility of the *IESO*.

5.3.4 Where:

5.3.4.1 the quantity of a *physical service* delivered to or withdrawn from the *IESO-controlled grid* by a *registered market participant* is reduced relative to that *registered market participant's* most recent valid *bid* or *offer*; and

5.3.4.2 such reduction is initiated pursuant to *reliability standards* by an entity, other than the *IESO*, having authority under such *reliability standards*;

the *registered market participant* shall not be entitled to compensation for any financial loss suffered as a result of such action.

Where such reduction was initiated by the *IESO*, the *registered market participant* shall be entitled to compensation, which shall be calculated and paid in accordance with section 3.5 of Chapter 9.

5.4 Reliability Policy for Area Supply

5.4.1 In coordination with *transmitters*, the *IESO* may develop and apply specific *security* criteria in areas of the *IESO-controlled grid* where the consequences of *contingency events* are localized and do not have a significant adverse impact on the *reliability* of the *IESO-controlled grid* ("*local areas*").

5.4.2 The following criteria shall be used to assess the *security* of a *local area*, as determined at the delivery point demarcating the boundary between the *local area* and the remainder of the *IESO-controlled grid*, on the one hand, and individual and collective *connection points* of the *IESO-controlled grid*, on the other:

5.4.2.1 the extent to which severe *contingency events* are experienced; and

5.4.2.2 the *reliability* of transmission *facilities* which directly affect the exchange of electricity to the *local area*.

5.4.3 The *IESO* shall coordinate with *transmitters* to review the performance at *connection points* at least once annually in order that they can jointly assess the *reliability* of *local areas*.

5.5 Interconnection Assistance

5.5.1 The *IESO* shall use and support *interconnected systems* in accordance with agreements between the *IESO* and other *security coordinators, control area operators* or *interconnected transmitters* and to the extent necessary to maintain the *security* of the *IESO-controlled grid*.

5.5.1A Information provided to the *IESO* under an *interconnection agreement* by a *security coordinator*, *control area operator* or *interconnected transmitter* and identified by the person providing the information as confidential shall be *confidential information* and shall not be disclosed or made available without the prior written consent of the particular *security coordinator, control area operator* or *interconnected transmitter*.

5.5.2 In requesting assistance from *market participants* and from other *security coordinators*, the *IESO* shall take effective action in the *IESO control area* prior to, or concurrently with, similar action being taken by the *interconnected system* providing assistance.

5.5.3 All agreements entered into by the *IESO* and other *security coordinators* relating to *security* shall meet all applicable *reliability standards*.

5.6 Inadvertent Interchange

5.6.1 Inadvertent interchange is the difference between the scheduled interchange on a single *interconnection*, or the sum of scheduled interchanges with several *interconnected systems*, on the one hand, and the actual metered flow on the *interconnection* point(s), on the other.

5.6.2 Inadvertent interchange shall be addressed in any agreement relating to *security* between the *IESO* and other *security coordinators*. The means used to mitigate inadvertent interchange shall respect all applicable *reliability standards.*

5.7 The Management of Violations to Security Limits

5.7.1 When there is a violation of a *security limit* on the *IESO-controlled grid* while in a *normal operating state*, the sequence of control actions taken by the *IESO* shall be defined in its operating procedures and instructions.

5.7.2 The operating procedures and instructions of the *IESO* shall allow the use of market mechanisms to the maximum extent possible for purposes of responding to violations of *security limits*.

5.7.3 Where market mechanisms fail or are not sufficient to maintain the *security* of the *IESO-controlled grid*, the *IESO* may direct *market participants* to take actions to either prevent the loss of *non-dispatchable load* or to prepare for *contingency events*.

5.8 Operation Under an Emergency Operating State

5.8.1 Once an *emergency operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.8.1.1 [Intentionally left blank]

5.8.1.2 [Intentionally left blank]

5.8.1.3 [Intentionally left blank]

5.8.1.4 coordinating with other *security coordinators*; acquiring *emergency energy* in accordance with section 2.3.3A;

5.8.1.5 issuing directions to *market participants* to reduce *demand* through voltage reductions and interruptions in accordance with section 10.3; and

5.8.1.6 operate to those *security limits* appropriate for an *emergency operating state* to allow for increased power transfers.

5.9 Operation Under a High-Risk Operating State

5.9.1 Once a *high-risk operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.9.1.1 [Intentionally left blank]

5.9.1.2 [Intentionally left blank]

5.9.1.3 [Intentionally left blank]

5.9.1.4 operating to *security limits* appropriate for a *high-risk operating state*;

5.9.1.5 coordinating with neighbouring *security coordinators*;

5.9.1.6 issuing directions to *market participants* to reduce *demand* through voltage reductions or interruptions in accordance with section 10.3; and

5.9.1.7 temporarily and selectively increase the level of *security* on the *IESO-controlled grid*.

5.10 Restoration of System Security Following a Contingency Event

5.10.1 *Market participants* shall be prepared for, shall be able to manage and shall take such actions as may be necessary to restore *security* of the *IESO-controlled grid* following a *contingency event*, as directed by the *IESO*.

5.10.2 The *IESO* shall establish:

5.10.2.1 procedures that identify the steps necessary to restore the operation of the *IESO-controlled grid* to an *emergency operating state* respecting corresponding *security limits*, within 30 minutes or, where a *high risk operating state* existed on some part of the *IESO-controlled grid* prior to the *contingency event*, within 15 minutes;

5.10.2.2 procedures to attempt to restore supply first to individual loads identified by *market participants* as critical in nature, once the minimum acceptable level of *security* on the *IESO-controlled grid* has been restored; and

5.10.2.3 in consultation with relevant *market participants*, procedures to restore the operation of the *IESO-controlled grid* and of *facilities connected* to a *transmission system* that forms part of the *IESO-controlled grid* following automatic *outages*.

6. Outage Coordination

6.1 Introduction

6.1.1 The objectives of this section 6 are to enable the *IESO* to review and assess the impact of *outage* schedules on the fulfillment by the *IESO* of its *reliability-related* responsibilities under the Electricity Act, 1998, its *license*, and the *market rules*, to require *market participants* to obtain the approval of the *IESO* in respect of *planned outage* schedules and to permit the *IESO* to reject, revoke *advance approval* of and recall *outages* that may have an impact on the *reliability* of the *IESO-controlled grid* or a material impact on the operation of the *IESO-administered markets*.

6.1.2 The *IESO* shall maintain a database of all submissions to the *outage* planning and scheduling process.

6.1.3 The *IESO* shall develop, and include in the applicable *market manual*, a full list of the equipment and *facilities* the *outage* of which must be reported to and scheduled with the *IESO* in accordance with this section 6. The *IESO* shall use as the basis for including *facilities* and equipment on this list that any change or anticipated change to the *facilities* or equipment could have a material effect on the value of an operating *security limit*, the *reliable* operation of *IESO-controlled grid* or operation of the *IESO-administered markets*, including, but not be limited to, the following:

6.1.3.1 *facilities* forming part of the *IESO-controlled grid*;

6.1.3.2 *generation facilities* and auxiliary equipment connected to the *IESO-controlled grid* or in respect of which a *generator* is participating in the *real-time markets*;

6.1.3.3 protection systems; and

6.1.3.4 communication equipment, including related hardware and software systems.

6.1.4 [Intentionally left blank]

6.1.5 Nothing in this section 6 shall relieve a *market participant* from its responsibility for and arising from the performance of all work relating to any *outage* or test, whether in respect of energized or de-energized *facilities* or equipment, including, but not limited to, its responsibility in respect of worker safety.

6.1.6 No *market participant* shall remove equipment or *facilities* from service except in accordance with this section 6 unless such removal from service is necessary to prevent damage to the *market participant's* equipment or *facilities* or to protect the safety of employees, the public or the environment. If any equipment or *facilities* are removed from service for these reasons, the *market participant* shall promptly notify the *IESO*.

6.1.7 The *IESO* shall coordinate *outages* with *market participants* except that, with respect to *outages* to any portion of the *transmission system* during a *normal operating state*, the applicable *transmitter* shall, pursuant to the Transmission System Code, coordinate the *outage* with affected *market participants* directly connected to that portion of the *transmission system* unless the *IESO* determines it necessary to coordinate such activities in order to maintain *reliability*.

6.2 Outage Planning

6.2.1 Each *market participant* shall inform the *IESO* of its long-term plans for *outages* in accordance with the provisions of this section 6.2.

6.2.2 Each *market participant* shall establish its *outage* planning process in such manner as will enable it to comply with its reporting and scheduling obligations under this section 6. Without limiting the generality of the foregoing, *market participants* shall be required to plan *outages* at least 33 calendar days in advance of the anticipated date of the *planned outage* and may be required by the *IESO* to plan *outages* further in advance than 33 calendar days as the *IESO* may determine appropriate.

6.2.2A *Market participants* applying to register their *facilities* as *transitional scheduling generators* shall provide, as part of the information required by section 2.2 of Chapter 7, a schedule of up to two *planned outages* per calendar year per *facility* that are demonstrably related to:

a) contractual obligations owed to *OEFC* or a third party in respect of a *transitional scheduling generator*, or

b) significant resource mobilization issues pursuant to such contractual obligations.

Requests for 14-Day Advance Approval – Generation Facility Outages

6.2.2B A *market participant* may request *14-day advance approval* for one *planned outage* for a *generation facility* per calendar year. If the *IESO* either:

- does not grant 14-day advance approval for the planned outage; or
- does grant 14-day advance approval but subsequently revokes the 14-day advance approval or recalls the planned outage;

the *market participant* may make a second request for *14-day advance approval* for that *planned outage* for that *generation facility* in the same calendar year. If the *IESO* then either:

- does not grant 14-day advance approval for the planned outage; or
- does grant 14-day advance approval but subsequently revokes the 14-day advance approval or recalls the planned outage;

the *market participant* may make a third request for *14-day advance approval* for that *planned outage* for that *generation facility* in the same calendar year.

6.2.2C A *market participant* may request *14-day advance approval* for two *planned outages* per calendar year for *generation units* within a single *generation facility* or for separate *generation facilities* with co-dependent electricity production provided that:

- the *market participant* can satisfy the *IESO* that the two *planned outages* are co-dependent; and
- the *market participant* identifies the total capacity impact for the *generation facility* or *generation facilities* in question for each *planned outage*.

If the *IESO* either:

- does not grant *14-day advance approval* for a co-dependent *planned outage*; or
- does grant *14-day advance approval* but subsequently revokes the *14-day advance approval* or recalls a co-dependent *planned outage*;

the *market participant* may make a second request for *14-day advance approval* for that co-dependent *planned outage* in the same calendar year. If the *IESO* then either:

- does not grant *14-day advance approval* for the co-dependent *planned outage*; or
- does grant *14-day advance approval* but subsequently revokes the *14-day advance approval* or recalls the co-dependent *planned outage*;

the *market participant* may make a third request for *14-day advance approval* for that co-dependent *planned outage* for that *generation facility* in the same calendar year.

6.2.2D A *market participant* may request *14-day advance approval* of *planned outages* for a *generation facility* more often than permitted under sections 6.2.2B and 6.2.2C. The *market participant* must satisfy the *IESO* as to why the *planned outages* should be considered for *14-day advance approval*.

Requests for 14-Day Advance Approval – Transmission, Distribution and Load Equipment Outages

6.2.2E A *market participant* may request *14-day advance approval* for up to two *planned outages* per calendar month for:

- equipment associated with a *load facility*;
- transmission equipment; or
- distribution equipment.

6.2.2F A *market participant* may request *14-day advance approval* for *planned outages* for transmission equipment, distribution equipment or equipment associated with a *load facility* more often than permitted under sections 6.2.2E. The *market participant* must satisfy the *IESO* as to why the *planned outage* should be considered for *14-day advance approval*.

IESO Obligation to Consider Planned Outages for 14-Day Advance Approval

6.2.2G The *IESO* shall consider all *planned outages* submitted under sections 6.2.2B, 6.2.2C, and 6.2.2E for *14-day advance approval*.

6.2.2H The *IESO* may consider *planned outages* submitted under sections 6.2.2D and 6.2.2F for *14-day advance approval*.

IESO Obligation to Include Planned Outages in Weekly Assessments

6.2.3 The *IESO* shall include in the weekly assessments referred to in section 7.3.1.3 all *outages* planned or scheduled by *market participants* to occur in the immediately following 33 calendar days as reported or scheduled by *market participants* and shall include in the quarterly assessments referred to in section 7.3.1.2 all *outages* planned or scheduled to occur in the immediately following 18 months as reported or scheduled by *market participants*.

Transmitter and Generator Obligation to Provide Planned Outage Information for 18-Month Assessments

6.2.4 To support the 18-month assessments referred to in section 7.3.1.2, and subject to section 6.2.5, for those *facilities* and equipment on the list developed in accordance with section 6.1.3, *transmitters* and *generators* shall, as frequently as may be necessary to maintain the accuracy of the information provided, report to the *IESO* the *outage* plans for transmission *facilities* forming part of the *IESO-controlled grid* and for *generation facilities*, respectively, as follows:

6.2.4.1 for *outages* starting 3 months or more in the future, those with a scheduled duration of 5 days or more; and

6.2.4.2 for *outages* starting less than 3 months in the future, those with a scheduled duration of 4 hours or more.

Exclusions of Outages for Generation Facilities

6.2.5 Notwithstanding any other provision of section 6, *outages* to the following *generation facilities* do not need to be reported to support the 18-month assessments referred to in section 7.3.1.2:

6.2.5.1 in the case of all *generators, generation facilities* having a *capacity* of less than 20 MW; or

6.2.5.2 in the case of a *generator* whose total available capacity inside the *IESO control area* exceeds 4000 MW, *generation facilities* that represent less than 0.5 percent of the total *capacity* of such *generator,* unless the *generation facilities* have been identified by the *IESO* as affecting the *reliability* of the *IESO-controlled grid.* The *IESO* shall notify the relevant *generators* of any *generation facilities* so identified.

6.3 Outage Scheduling with the IESO

Planned Outages

6.3.1 Subject to section 6.1.3, each *market participant* shall, no later than 33 calendar days prior to a *planned outage*, submit its current schedule of all *planned outages*, regardless of duration, to the *IESO*.

6.3.2 A *planned outage* submitted by a *market participant* pursuant to section 6.3.1 shall represent the intent of the *market participant* to take the relevant equipment out of service at the scheduled time and to return the relevant equipment to service at the scheduled time.

6.3.3 The *IESO* shall reflect all *planned outages* submitted by *market participants* pursuant to section 6.3.1 in the weekly and monthly assessments referred to in section 6.2.3.

Forced Outages

6.3.4 Each *market participant* shall to the maximum extent possible notify the *IESO* in advance of a *forced outage* and provide a brief description of the nature and causes of the *forced outage.* When such advance notice cannot be given, the *market participant* shall promptly notify the *IESO* of the occurrence of a *forced outage* and provide a brief description of the nature and causes of the *forced outage*.

6.3.5 Whenever, in the opinion of the *IESO*, a *forced outage* has had a significant impact on the *reliability* of the *IESO-controlled grid*, or gives rise to potential *reliability* concerns, the *IESO* may require the *market participant* experiencing the *forced outage* to provide a detailed description of the nature and causes of the *forced outage* to the *IESO*. Such description of the *forced outage* shall be provided as soon as practicable and in any event within 48 hours, or within such longer period of time as may be agreed to by the *IESO* in any given case, following the start of the *forced outage.* The *IESO* may also require the *market participant* experiencing the *forced outage* to provide a detailed description of the steps that the *market participant* intends to take to prevent any recurrence of the circumstances that led to the *forced outage*. Such description shall also be provided as soon as practical and in any event within 48 hours, or within such longer period of time as may be agreed to by the *IESO*, following the start of the *forced outage*.

Replacement Energy to Support Planned Outages

6.3.6 A *generator* may, no later than the time specified in section 6.4.1, in requesting a *planned outage* in accordance with section 6.3.1, notify the *IESO* that the *generator* shall arrange replacement *energy offers* in the form of an import to support the *outage* request. A *generator* may, when requesting an extension to an *outage* under section 6.4.7 or rescheduling an *outage* under section 6.4.10, notify the *IESO* that the *generator* shall arrange replacement *energy offers* in the form of an import to support the *outage* extension or re-scheduling request. For certainty, this section shall not under any circumstances impose any explicit or implicit obligation on either a *generator* to so notify the *IESO*, or if so notified, the *IESO* to approve or accept any such arrangement. Upon notice to the *IESO*, a *generator* may withdraw the arrangement for replacement *energy offers* at any time up to final approval of the *outage* or up to the final approval of the extension to or rescheduling of the *outage.*

6.3.7 The *generator* shall provide the following information to the *IESO* when in accordance with section 6.3.6 it either submits a *planned outage* request or requests the extension to or rescheduling of an *outage*:

6.3.7.1 Subject to the approval of the *IESO*, the *intertie* zone or zones through which the replacement *energy* is intended to be scheduled; and,

6.3.7.2 The *registered market participant* associated with a *registered facility* that is a *boundary entity* that shall submit the *offers* and, pursuant to section 7.5.8A of Chapter 7, schedule the replacement *energy* if *dispatched* by the *IESO.*

6.3.8 The *IESO* may limit the number and aggregate size of *outages* supported by replacement *energy* and, where the number and aggregate size of *outages* is limited the *IESO* shall determine the precedence of the *outages*, in accordance with sections 6.4.13 through 6.4.18.

6.3.9 The *IESO* may specify and inform the *generator* of the minimum amount of replacement *energy* in megawatts and the duration of *offers* necessary to support the *planned outage* request or the request for the extension to or rescheduling of the *outage*.

6.3.10 If the *registered market participant* associated with a *registered facility* that is a *boundary entity* referred to in section 6.3.7.2 fails to submit *offers* for the replacement *energy*, that have been arranged by the *generator*, the *generator* shall be subject to the financial penalties calculated in accordance with the provisions of section 6.6.8 of Chapter 3.

6.4 Confirmation of Outage Schedules and IESO Approval of Outage Schedules

6.4.1 In order to obtain *IESO* approval of a *planned outage*, a *market participant* shall confirm a *planned outage* with the *IESO* under the timelines specified in section 6.4.1A. At the time of the confirmation, the *market participant* shall:

6.4.1.1 provide information about the recall of the *planned outage*, including the time required to return the *facilities* or equipment to service and other applicable conditions of recall;

6.4.1.2 if a *generator*, *distributor* or *wholesale consumer*, provide the costs or expenses associated with the cancellation or deferral of the *planned outage* and the estimated costs or expenses associated with the recall of the *planned outage*; and

6.4.1.3 confirm, if applicable, the request for *14-day advance approval* for the *planned outage*.

6.4.1A If requesting a *14-day advance approval* of a *planned outage*, the *market participant* shall confirm the *planned outage* with the *IESO* no earlier than 33 calendar days and no later than 10:00 EST on the 21st calendar day prior to the start date of the *planned outage*.

If requesting a *two-day advance approval* of a *planned outage*, the *market participant* shall confirm the *planned outage* with the *IESO* no earlier than 33 calendar days and no later than 10:00 EST on the third *business day* prior to the start date of a *planned outage*.

6.4.2 Where the scheduling of *planned outages* submitted by different *market participants* conflicts such that the *planned outages* cannot both or all be approved by the *IESO*, the *IESO* shall inform the affected *market participants* and request that they resolve the conflict. Should the conflict remain unresolved, the *IESO* shall determine which of the *planned outages* can be approved on the basis of the precedence accorded to each *planned outage* pursuant to sections 6.4.13 to 6.4.18.

6.4.3 No *planned outage* shall occur or be permitted by a *market participant* to occur unless:

6.4.3.1 the *planned outage* has been confirmed with the *IESO* in accordance with section 6.4.1;

6.4.3.2 the *planned outage* has been approved by the *IESO* in accordance with this section 6.4;

6.4.3.3 immediately prior to the scheduled commencement of the *planned outage* or at a pre-arranged time specified by the *IESO* when providing the *advance approval* referred to in section 6.4.4.5, the *market participant* has requested from the *IESO* and has received the *IESO*'s final approval to the *planned outage*; and

6.4.3.4 the removal from service of the relevant equipment or *facilities* is undertaken under the direction of the *IESO* where the *IESO* has made the determination referred to in section 6.4.4.6.

6.4.4 The *IESO* shall:

6.4.4.1 provide *advance approval* for a *planned outage* confirmed to it pursuant to section 6.4.1 and shall provide its final approval to the *planned outage* pursuant to section 6.4.3.3 unless it determines, based primarily on the weekly assessment referred to in section 7.3.1.3 with emphasis on the first two weeks and on the daily assessments referred to in section 7.3.1.4, that the *planned outage*, including but not limited to a *planned outage* identified by an *embedded generator*, will or is reasonably likely to have an adverse impact on the *reliable* operation of the *IESO-controlled grid;*

6.4.4.2 following receipt of confirmation pursuant to section 6.4.1, assess each confirmed *planned outage*;

6.4.4.3 following receipt of an *outage* submission pursuant to section 6.2.1 or 6.3.1, or of confirmation pursuant to section 6.4.1, advise the relevant *market participant* of the existence of any conflict with a *planned outage* planned by another *market participant*;

6.4.4.4 if the *market participant* confirmed the *planned outage* with the *IESO* under section 6.4.1, advise the relevant *market participant* of the expected outcome of the approval process;

6.4.4.4A if the *market participant* confirmed its *planned outage* and request for *14-day advance approval* under section 6.4.1A, advise the *market participant* whether or not *14-day advance approval* of the *planned outage* has been granted no later than 14:00 EST on the last *business day* that is at least 14 calendar days before the schedule start date of the *planned outage*. Where the *IESO* does not grant *14-day advance approval*, the *IESO* shall consider the *planned outage* for *two-day advance approval*;

6.4.4.5 if applicable advise the *market participant* of the *two-day advance approval* or rejection of the *planned outage* no earlier than 10:00 EST on the third *business day* prior to the date of the *planned outage* and no later than 14:00 EST on the second *business day* prior to the day on which the *planned outage* is scheduled to commence; and

6.4.4.6 when providing the final approval referred to in section 6.4.4.1, advise the *market participant* if the confirmed *planned outage* is to be undertaken under the direction of the *IESO* where the *IESO* has made a determination that this is necessary to maintain the *reliability* of the *IESO-controlled grid*. If it is known in advance, the *IESO* will advise the *market participant* of this requirement when providing the *advance approval* referred to in sections 6.4.4.4A or 6.4.4.5 or as soon as possible thereafter.

6.4.5 Where the *IESO* does not provide *advance approval* of a *planned outage* or does not give its final approval to a *planned outage* pursuant to section 6.4.4, the *IESO* shall work with the relevant *market participant* to re-schedule the *planned outage* to a date and time at which the *planned outage* will not or is not reasonably likely to have an adverse impact on the *reliable* operation of the *IESO-controlled grid*. In re-scheduling the *planned outage*, the *IESO* shall where reasonably practicable take into account the date and time preferences of the *market participant*.

Request on Short Notice

6.4.6 If for any reason a *market participant* is unable to confirm a *planned outage* in accordance with section 6.4.1, the *market participant* may make a request to the *IESO* for approval of a *planned outage* after 10:00 EST on the third *business day* prior to the date proposed by the *market participant* for the *planned outage*. The *IESO* will process these short notice *outage* requests based on time stamp priority and on a best effort basis following the completion of its *reliability* assessments.

Extensions

6.4.7 Each *market participant* shall notify the *IESO* if a *planned outage* which has been approved by the *IESO* will have a duration which exceeds the duration originally approved by the *IESO*, which notice shall include a request that the *IESO* approve the extension. Such notice shall be provided to the *IESO* as soon as possible and will be treated as a new *outage* request.

6.4.8 If the *IESO* determines that an extension to the duration of a *planned outage* will or is reasonably likely to adversely affect the *reliability* of the *IESO-controlled grid* or will or is reasonably likely to require the re-scheduling of a *planned outage* confirmed to the *IESO* pursuant to section 6.4.1 or the revoking of *advance approval*, deferral or recall of a *planned outage* approved pursuant to section 6.4.4, the *IESO* shall reject such extension and the *market participant* shall use its reasonable best efforts to ensure that the duration of the *planned outage* does not exceed the duration originally approved by the *IESO* or such longer period as the *IESO* may advise in rejecting the extension requested.

Revoke Advance Approvals

6.4.9 The *IESO* may, where necessary to maintain the *reliability* of the *IESO-controlled grid*, revoke an *advance approval* of a *planned outage*. Without limiting the generality of the foregoing, the *IESO* may revoke an *advance approval* if:

6.4.9.1 the *IESO* determines that either an *emergency operating state* or a *high-risk operating state* is occurring or is reasonably likely to occur at the time at which the *planned outage* would otherwise take place; or

6.4.9.2 necessary to avoid recalling a *planned outage* pursuant to section 6.4.11.

A *planned outage* that receives *advance approval* under section 6.4.4 but does not receive final approval pursuant to section 6.4.3.3 shall be considered to have had its *advance approval* revoked.

6.4.10 Where the *IESO* revokes *advance approval* of a *planned outage* pursuant to section 6.4.9, the *market participant* may elect either to defer or to cancel the *outage*. When the *market participant* elects to defer the *outage*, the *IESO* shall work with the relevant *market participant* to re-schedule the *planned outage* to a date and time at which the *planned outage* will not or is not reasonably likely to have an adverse impact on the reliable operation of the *IESO-controlled grid*. In re-scheduling the *planned outage*, the *IESO* shall where reasonably practicable take into account the date and time preferences of the *market participant*. A *planned outage* that is re-scheduled under this section is not considered a short-notice *planned outage* for the purposes of compensation under section 6.7.

Recalls

6.4.11 The *IESO* may, where necessary to maintain the *reliability* of the *IESO-controlled grid*, recall a *planned outage* that has already commenced, having due regard to the time needed to return the *facilities* or equipment to service as identified by the relevant *market participant* pursuant to section 6.4.1.1 and shall so advise the relevant *market participant*. Such *market participant* shall arrange for the accelerated return to service of the *facilities* or equipment in accordance with the schedule identified by the *market participant* pursuant to section 6.4.1.1. The *IESO* shall not recall a *planned outage* unless further control action is required and it has revoked *advance approval* or rejected requests for approval of all other *planned outages* the revocation or rejection of which could eliminate the need to recall the *planned outage* that has already commenced.

Embedded Generators

6.4.12 Each *distributor* shall, in reporting to the *IESO* pursuant to sections 6.2 and 6.3, identify to the *IESO* any *outages* that potentially constrain an *embedded generator* that is connected to its *distribution system.*

Determining Precedence of Outages

6.4.13 The *IESO* shall time stamp each *outage* submission received by the *IESO*. Where the *IESO* is required or permitted by this section 6 to approve, reject, revoke *advance approval* of or recall one or more *planned outages*, such *planned outages* shall:

6.4.13.1 be given advance or final approval in order of precedence determined on the basis of sections 6.4.14 to 6.4.18; and

6.4.13.2 be rejected, be re-scheduled, have *advance approval* revoked or be recalled in reverse order of precedence determined on the basis of sections 6.4.14 to 6.4.18.

6.4.13A Subject to section 6.2.2A and notwithstanding section 6.4.13, where the *IESO* is required or permitted by this section 6 to approve, reject, revoke *advance approval* of or recall one or more *planned outages* referred to in section 6.2.2A that were submitted at least 30 days prior to the *market commencement date*, such *planned outages* shall:

- be the first to be given advance or final approval; and

- be the last to be rejected, revoked or recalled.

6.4.14 Where a *market participant* confirms a *planned outage* referred to in a previous *outage* submission prior to the applicable confirmation deadline referred to in section 6.4.1A without changing the commencement, duration or nature of the *planned outage* as described in that previous *outage* submission, the time stamp associated with such previous *outage* submission shall be used by the *IESO* in determining the precedence to be given to the *planned outage*. Where a *market participant* confirms a *planned outage* referred to in a previous *outage* submission subsequent to the applicable confirmation deadline referred to in section 6.4.1A without changing the commencement, duration or nature of the *planned outage* as described in that previous *outage* submission, the time stamp associated with the time of receipt by the *IESO* of such confirmation shall be the time stamp used by the *IESO* in determining the precedence to be given to the *planned outage*.

6.4.15 Where a *market participant* gives notice of a change in the commencement, duration or nature of a *planned outage* relative to the most recent *outage* submission, the *IESO* shall stamp such notice with the time at which it was received by the *IESO*, which time shall be used by the *IESO* in determining the precedence to be given to the *planned outage*. Where such notice reflects only a shortening in the duration of a *planned outage* relative to the most recent *outage* submission for that *planned outage*, the time stamp associated with such previous *outage* submission shall be retained in determining the precedence to be given to the *planned outage*.

6.4.15A Where notice is given in respect of a *transitional scheduling generator* of a change in the commencement, duration or nature of a *planned outage* relative to an outage submission referred to in section 6.2.2A no later than 10:00 EST on the third *business day* prior to the date of the *planned outage*, the *IESO* shall use the time stamp associated with such previous *outage* submission in determining the precedence to be given to the *planned outage*.

6.4.16 Where:

6.4.16.1 the *IESO* revokes *advance approval* of a *planned outage* prior to the commencement thereof;

6.4.16.2 the *market participant* subsequently re-confirms the *planned outage* with the *IESO*; and

6.4.16.3 the *IESO* approves the re-confirmation,

the time stamp of the approved *planned outage* prior to the revocation of *advance approval* shall be deemed to be the time stamp of the re-confirmed *planned outage* for purpose of determining the precedence to be given to the *planned outage*.

6.4.17 Where:

6.4.17.1 a *planned outage* is, within 7 days of the date on which it was scheduled to commence, required by the *IESO* pursuant to this section 6 to be re-scheduled;

6.4.17.2 the *IESO* did not identify, through one or more of its reliability forecasts, a concern relating to reliability of the *IESO-controlled grid* in respect of the time scheduled for the *planned outage*; and

6.4.17.3 the *planned outage* is re-scheduled to a date that is within 9 days of the originally scheduled commencement date,

the time stamp of the *planned outage* prior to the re-scheduling will be deemed to be the time stamp of the re-scheduled *planned outage* for purposes of determining the precedence to be given to the *planned outage*.

6.4.18 Where the *IESO* has rejected a *planned outage* pursuant to section 6.4.5, the time of receipt of confirmation of the *planned outage* pursuant to section 6.4.1 shall be retained until such time as the confirmed commencement date of the *planned outage* has passed so as to facilitate the possible consent to the occurrence of the *planned outage* on the confirmed commencement date, in the event that the *reliability* concerns that prompted the rejection cease to preclude the occurrence of the *planned outage*.

6.4A Return of Equipment or Facilities to Service

6.4A.1 No *market participant* shall return to service any equipment or *facilities* that are undergoing a *planned outage* unless:

6.4A.1.1 immediately prior to its return to service, the *market participant* has requested and has received the *IESO's* approval to return the equipment or *facilities* to service; and

6.4A.1.2 the return to service of the relevant equipment or *facilities* is undertaken under the direction of the *IESO* where the *IESO* has made the determination referred to in section 6.4A.2.3.

6.4A.2 The *IESO* shall:

6.4A.2.1 approve the return to service of equipment or *facilities* that are undergoing a *planned outage* unless it determines that such return to service will or is reasonably likely to have an adverse impact on the *reliability* of the *IESO-controlled grid*;

6.4A.2.2 promptly notify the *market participant* if a determination is made that a return to service of equipment or *facilities* will or is reasonably likely to have an adverse impact on the *reliability* of the *IESO-controlled grid*; and

6.4A.2.3 when providing the approval referred to in section 6.4A.2.1, advise the *market participant* if the return to service of equipment or *facilities* is to be undertaken under the direction of the *IESO* where the *IESO* has made a determination that this is necessary to maintain the *reliability* of the *IESO-controlled grid*.

6.4A.3 Where the *IESO* does not approve the return to service of equipment or *facilities* pursuant to section 6.4A.2.1, the *IESO* shall, subject to final confirmation by the *IESO* pursuant to 6.4A.1, advise the *market participant* when the equipment or *facilities* may be returned to service.

6.4B Notification of Commencement and Completion of Planned Outages

6.4B.1 Each *market participant* shall notify the *IESO*:

6.4B.1.1 of the commencement of a *planned outage* at the time the relevant equipment or *facilities* are removed from service; and

6.4B.1.2 of the completion of a *planned outage* at the time the relevant equipment or *facilities* are fully returned to service.

6.5 Information

6.5.1 Each *transmitter* and each *generator* shall provide to the *IESO* such *outage* information as may be requested by the *IESO* to enable the *IESO* to review and schedule *outages*.

6.5.2 Subject to the confidentiality provisions of Chapter 3, the *IESO* shall *publish* the *planned outage* information provided to it pursuant to section 6.5.1.

6.5.3 Notwithstanding any other provision of these *market rules*, *planned outage* information that is provided to the *IESO* by *market participants* pursuant to this Chapter may be exchanged between the *IESO* and other *security coordinators, control area operators*, and *interconnected transmitters* who are signatories to the *NERC confidentiality agreement* or who are otherwise legally bound to withhold the information from any person competing with the *market participant* that provided the information.

6.5.4 [Intentionally left blank – section deleted]

6.5.5 The *IESO* shall *publish generator outage* information aggregated by fuel type based on information provided to it by *market participants*.

6.6 Tests

6.6.1 A *market participant* who wishes to engage in a test that could affect the *reliability* of the *IESO-controlled grid* or the operation of the *IESO-administered markets* shall provide the information referred to in section 6.6.2 to the *IESO*.

6.6.2 As a minimum, the information referred to in section 6.2.1 shall identify:

6.6.2.1 the equipment involved;

6.6.2.2 the relevant details of contracts or agreements as they relate to the test activities;

6.6.2.3 preferred and alternative dates and times for the conduct of the test activities;

6.6.2.4 unusual system configurations or setup;

6.6.2.5 the expected impact of the test activities on power flows, voltage and frequency, and of any other dynamic that could interfere with the *reliability* of the *IESO-controlled grid*;

6.6.2.6 details of special readings or observations, as available; and

6.6.2.7 the names of and methods of communication with personnel who will be involved in the test activities and who may be contacted with respect thereto.

6.6.3 Tests covered by the requirements of this section 6.6 shall include, but are not limited to:

6.6.3.1 the deliberate application of short circuits;

6.6.3.2 stability tests of *generation facilities* and transmission *facilities*;

6.6.3.3 planned actions which could cause abnormal voltage, frequency or overload; and

6.6.3.4 planned abnormal station or system configurations with inherent risk.

6.6.4 The *IESO* shall permit a test referred to in this section 6.6 to be performed if the *IESO* determines that the performance of the test will not have an adverse effect on the *reliability* of the *IESO-controlled grid* or on the operation of the *IESO-administered markets.*

6.6.5 In permitting a test to be performed, the *IESO* shall endeavour to permit the test to be performed at the time and on the date preferred as identified by the *market participant* pursuant to section 6.6.2.3.

6.6.6 This section 6.6 also applies to tests conducted pursuant to section 5 of Chapter 4.

6.6.7 During performance testing, a *market participant* shall keep the *IESO* informed of the expected operating capability of the *market participant's generation facility* using the outage management process as specified in the applicable *market manual*.

6.7 Compensation

Revoke Advance Approvals or Recalls

6.7.1 *Transmitters* whose *outages* are rejected or have *advance approvals* revoked or have *outages* recalled by the *IESO* shall not be entitled to compensation for any costs, losses or damage associated with such rejection, revocation or recall.

6.7.2 *Generators*, *distributors* or *wholesale consumers* whose *outages* have *advance approval* revoked or have outages recalled by the *IESO* shall, subject to the exceptions defined in sections 6.7.3 and 6.7.3A, be entitled to compensation for out-of-pocket expenses associated with such revocation or recall only if:

6.7.2.1 the *outage* was originally approved by the *IESO* pursuant to 6.4.4;

6.7.2.2 the *outage* was recalled or had *advance approval* revoked by reason of a material error in the *IESO's* demand forecast, a failure of *generation facilities* within the *IESO control area*, a failure of *facilities* forming part of the *IESO-controlled grid* or a failure of *interconnection facilities*;

6.7.2.3 the out-of-pocket expenses were identified to the *IESO* in accordance with section 6.4.1.2; and

6.7.2.4 the out-of-pocket expenses exceed $1000.00.

6.7.3 No *generator, distributor* or *wholesale consumer* shall be entitled to compensation under section 6.7.2 in respect of an *outage* that was approved by the *IESO* on short notice under section 6.4.6.

6.7.3A A *market participant* shall not be entitled to compensation under section 6.7.2 with respect to a *planned outage* of its *generation facility* that received a *14-day advance approval* and that *advance approval* was subsequently revoked by the *IESO* if:

6.7.3A.1 the IESO revoked the 14-day advance approval as a result of a forced outage of another generation facility with the same registered market participant as the generation facility that was the subject of the planned outage and the forced outage occurred before 14:00 E.S.T. on the second business day prior to the scheduled start of the planned outage; or

6.7.3A.2 the *14-day advance approval* was revoked as a result of a delayed return to service from a *planned outage* or *forced outage* of another *generation facility* with the same *registered market participant* as the *generation facility* that was the subject of the *planned outage*.

6.7.4 The out-of-pocket expenses claimed by *generators*, *distributors* or *wholesale consumers* pursuant to section 6.7.2 shall be subject to verification and audit by the *IESO* and shall, where paid, be recovered by the *IESO* in accordance with section 4.8 of Chapter 9.

6.7.5 A *generator*, *distributor* or *wholesale consumer* shall not be entitled to compensation for any costs, expenses, losses or damage associated with an *outage* which has been rejected by the *IESO* provided that, in exceptional circumstances and where a *generator*, *distributor* or *wholesale consumer* has suffered substantial financial harm as a direct result of such rejection, the *generator*, *distributor* or *wholesale consumer* may request that an *arbitrator* be appointed pursuant to section 2 of Chapter 3 to determine whether and the amount of any compensation which the *generator*, *distributor* or *wholesale consumer* shall be entitled to recover as a result of the rejection of the *outage* by the *IESO*. In the case of *generators*, no such compensation shall be recoverable under this section 6.7.5 unless the *generator* demonstrates that the amount claimed cannot be recovered through market prices.

6.7.6 Where a *generator*, *distributor* or *wholesale consumer planned outage* has been deferred as a result of the *IESO* either revoking *advance approval* of or recalling the *planned outage*, the compensation entitlement for each such deferral occurrence shall not exceed the compensation entitlement that would apply for cancellation as provided in section 6.4.1.2.

6.7.7 Each act of revocation or recall by the *IESO* shall be treated separately for compensation purposes.

7. Forecasts and Assessments

7.1 Forecasts Prepared by the IESO

7.1.1 The *IESO* shall produce and *publish* the following ongoing *demand* forecasts for Ontario or parts thereof:

7.1.1.1 [Intentionally left blank – section deleted]

7.1.1.2 on a daily basis, a forecast of *demand* for each of the 14 days following the current day, by hour;

7.1.1.3 on a weekly basis, a forecast of *demand* for the next 28 days, by day and by hour; and

7.1.1.4 on a quarterly basis, a forecast of *demand* for the next 18 months, by week.

7.1.1.5 [Intentionally left blank – section deleted]

7.1.2 The forecasts referred to in section 7.1.1 shall be prepared by the *IESO* in such form as may be specified in the applicable *market manual,* shall be used in conducting the assessments referred to in section 7.3, and shall, in the case of the forecast referred to in section 7.1.1.4, be included in the reports referred to in section 7.3.1.2.

7.1.3 The *IESO* shall *publish* the method to be used to perform the forecasts described in section 7.1.1.

7.1.4 [Intentionally left blank – section deleted]

7.1.5 Each *distributor, connected wholesale customer* and other load-serving entity shall, for the purpose of enabling the *IESO* to produce the forecasts referred to in section 7.1.1, provide to the *IESO* the load forecasts described in the applicable *market manual* in such form, at such time and having such resolution as may be specified in such *market manual.*

7.2 Basis for IESO Forecasts

7.2.1 The *IESO* shall develop forecasts of peak *demand* and *energy demand*, by area, that are based on, but potentially differ from, the forecasts provided to it by *distributors*, other load-serving entities and *connected wholesale customers* pursuant to section 7.1.5, and which account for the *demands* of loads not required to make forecasts. These forecasts shall be developed on an area basis, as required to meet the purposes of these forecasts.

7.3 Advance Assessments of System Reliability

7.3.1 The *IESO* shall prepare for the purposes referred to in section 7.4 and based on the information received pursuant to section 7.5.1 and such other information as the *IESO* considers appropriate, and *publish*, the following reports of its findings in relation to such *reliability* assessments:

7.3.1.1 [Intentionally left blank – section deleted]

7.3.1.2 on a quarterly basis and no later than 5 *business days* prior to the end of each calendar quarter, an assessment covering an eighteen-month period commencing with the following calendar month;

7.3.1.3 on a weekly basis and within two *business days* of the date of receipt from *market participants* of the weekly information specified in the *market manual* referred to in section 7.5.1, an assessment covering the third and fourth week of a four-week period commencing with the following day;

7.3.1.4 on a daily basis and not later than 17:00 EST on each day, an assessment covering a fourteen-day period commencing on the following day; and

7.3.1.5 as required, an assessment of the *reliability* of the *IESO-controlled grid*.

7.3.2 Any information derived from the s*ecurity* and *adequacy* assessment process shall be used to provide a basis for informing *market participants* about expected conditions on the *IESO-controlled grid* and in the *IESO-administered markets*. It is expected that the information will trigger appropriate responses under other market processes, such as *outage* coordination, and transmission investment planning.

7.3A Liability

7.3A.1 Notwithstanding section 13.1.2 of Chapter 1, no *market participant* shall be entitled to compensation from the *IESO* for any costs, loss or damage sustained by the *market participant* as a result of any difference between:

7.3A.1.1 *demand* as forecasted pursuant to section 7.1.1 and actual *demand*;

7.3A.1.2 conditions on the *IESO-controlled grid* as forecasted in the assessments referred to in section 7.3.1 and actual conditions on the *IESO-controlled grid*; or

7.3A.1.3 information contained in succeeding forecasts *published* pursuant to section 7.1.1 or reports *published* pursuant to section 7.3.1 that cover in whole or in part the same time frame.

7.3B Succession of Forecasts and Reports

7.3B.1 Each forecast *published* pursuant to section 7.1.1 or report *published* pursuant to section 7.3.1 shall, to the extent that it covers in whole or in part the same time frame as that covered in a previous *published* forecast or report, supercede such previous *published* forecast or report.

7.4 Purpose of Assessments

7.4.1 [Intentionally left blank – section deleted]

7.4.1.1 [Intentionally left blank – section deleted]

7.4.1.2 [Intentionally left blank – section deleted]

7.4.1.3 [Intentionally left blank – section deleted]

7.4.1.4 [Intentionally left blank – section deleted]

7.4.2 The *IESO* shall conduct the quarterly assessments referred to in section 7.3.1.2 to:

7.4.2.1 provide forecasts, by month, of expected *demand*, *generation capacity* and transmission capacity, *energy* capability of *generation facilities*, and the possibility of any *security*-related events on the *IESO-controlled grid* that could require contingency planning by *market participants* or by the *IESO*;

7.4.2.2 allow the *IESO* to identify exigencies potentially impacting on the coordination of *outages* that could give rise to shortfalls in *generation capacity* and thus provide information by which *market participants* could act to reschedule *outage* plans to avoid such projected shortfalls; and

7.4.2.3 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of the regional power systems to match generation and *demand*.

7.4.3 The *IESO* shall conduct the weekly assessments referred to in section 7.3.1.3 to:

7.4.3.1 provide forecasts, by day, of expected daily *demand*, *generation capacity* and transmission capacity, *energy* capability of *generation facilities*, exports and imports of *energy*, and the availability of transmission that may affect the *security* of the *IESO-controlled grid* or affect operational decisions to be taken by the *IESO* that must be made more than a day in advance;

7.4.3.2 allow the *IESO* to identify exigencies potentially impacting on the coordination of *outages* that may give rise to shortfalls in *generation capacity* and thereby assist *market participants* in finalizing *outage* plans and submitting *outage* schedules to the *IESO*; and

7.4.3.3 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of regional power systems to match generation and *demand*, particularly in peak seasons and peak periods.

7.4.4 The *IESO* shall conduct the daily assessments referred to in section 7.3.1.4 to:

7.4.4.1 provide forecasts, by day, of expected hourly *demand*, *generation capacity* and transmission capacity, *energy* capability of *generation facilities*, exports and imports of *energy*, and the availability of transmission that may affect the *security* of the *IESO-controlled grid* or affect operational decisions to be taken by the *IESO* that must be made more than a day in advance; and

7.4.4.2 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of regional power systems to match generation and *demand*, on a daily and hourly basis, particularly in peak seasons and in peak hours.

7.4.5 The *IESO* shall conduct the assessments referred to in section 7.3.1.5 to:

7.4.5.1 meet its obligations to maintain the *reliability* of the *IESO-controlled grid*;

7.4.5.2 meet the requirements of *standards authorities*; and

7.4.5.3 assist the *OEB* and the *OPA* in meeting their respective objectives.

7.5 Information Requirements

7.5.1 Each *market participant* shall, for the purpose of enabling the *IESO* to perform the *reliability* assessments referred to in section 7.3.1, provide to the *IESO* the information described in the applicable *market manual* in such form, at such time and having such resolution as may be specified in such *market manual*.

7.6 The Reporting of Reliability Assessments

7.6.1 The reports referred to in section 7.3.1 shall be prepared by the *IESO* in such form and shall contain such information as may be specified in the applicable *market manual*.

7.6.2 [Intentionally left blank – section deleted]

7.7 Updated and Related Reports

7.7.1 [Intentionally left blank – section deleted]

7.7.2 [Intentionally left blank – section deleted]

7.7.3 [Intentionally left blank – section deleted]

7.7.4 [Intentionally left blank – section deleted]

Interim Updates

7.7.5 The *IESO* may *publish* additional updated versions of any of the assessment reports referred to in section 7.3.1 in the event of changes that, in the *IESO*'s opinion, are significant and should be communicated to *market participants*.

Related Reports

7.7.6 From the material and assessments in the assessment reports referred to in section 7.3.1, the *IESO* may produce additional related reports as required by relevant *standards authorities*, the *IESO Board*, the *OEB*, the *OPA*, and the Government of Ontario.

7.8 [Intentionally left blank – section deleted]

7.8.1 [Intentionally left blank – section deleted]

7.8.2 [Intentionally left blank – section deleted]

7.9 Provision of Information to Transmitters

7.9.1 [Intentionally left blank – section deleted]

7.9.2 Notwithstanding any other provision of these *market rules*, the *IESO* may, if necessary to enable *transmitters* to prepare plans for the expansion or modification of the *IESO-controlled grid*, provide to relevant *transmitters* information provided by *market participants* pursuant to this Chapter regarding their forecasts and plans. Any such information which is *confidential information* shall be provided to *transmitters* on a confidential basis and the receiving *transmitter* shall use all reasonable endeavours to protect such *confidential information* and shall use such *confidential information* solely for the purpose of preparing plans for the expansion or modification of the *IESO-controlled grid*.

7.9.3 Where the *IESO* intends to disclose to a *transmitter confidential information* pertaining to a *market participant* pursuant to section 7.9.2, the *IESO* shall provide the *market participant* with advance notice of such intention and shall provide the *market participant* with a reasonable opportunity to make representation as to why the *confidential information* should not be disclosed.

7.10 IESO Actions

Actions Within Next Twelve Months

7.10.1 If the *IESO* identifies an adverse condition on the *IESO-controlled grid* that requires action to be initiated within the next twelve months in order to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* may:

- conduct and *publish* a *reliability* assessment in accordance with section 7.3.1.5; and
- take any additional steps necessary to ensure that the *reliability* of the *IESO-controlled grid is* maintained.

7.10.2 If the *IESO* does not believe that *market participants* have or will voluntarily put forward reasonable commitments for technically feasible options to alleviate the condition identified in section 7.10.1, the *IESO* may direct the *transmitter(s)* in the relevant location(s) to prepare a detailed proposal for the enhancement of the *IESO-controlled grid*. The *transmitter(s)* shall submit the proposal to the *OEB*, the *OPA*, and other governmental agencies having authority to approve the proposal, in the form of an application for approval of the enhancement. The *IESO* shall notify the *OEB* and the *OPA* of its identification of the adverse condition.

Actions Beyond the Next Twelve Months

7.10.3 If the *IESO* identifies an adverse condition on the *IESO-controlled grid* that does not require action to be initiated within the next twelve months, the *IESO*:

- shall notify the *OEB* and the *OPA* of its determination; and
- may provide support to the *OPA* in the *OPA's* assessment of the options that may be available for *market participants* or others to remove or alleviate the condition.

Actions Independent of IESO Recommendations

7.10.4 Nothing in this section 7.10 is intended to limit the ability of any *market participant* to file for approval a proposal to invest in *facilities* on the *integrated power system* that are not the subject of specific recommendations made by the *IESO*. A *market participant* interested in sponsoring a new or modified *connection* to the *IESO-controlled grid* may submit a *request for connection assessment* in accordance with section 6.1.6 of Chapter 4.

8. Special Protection Systems (SPS)

8.1 Objectives

8.1.1 *Special protection systems* ("*SPS*") have been installed in a number of locations on the *IESO-controlled grid* which automatically initiate one or more of the following control actions:

8.1.1.1 load rejection;

8.1.1.2 generation rejection;

8.1.1.3 generation runback;

8.1.1.4 shunt capacitor switching;

8.1.1.5 shunt reactor switching; and

8.1.1.6 cross-tripping.

8.1.2 The *IESO* shall direct the arming of *SPSs* installed on the *IESO-controlled grid* as necessary to:

8.1.2.1 increase the capability of power transfers on the *IESO-controlled grid;* or

8.1.2.2 provide additional *security* beyond that required to manage *contingency events* in a *normal operating state*.

8.1.3 New *SPSs* shall be installed and utilized on the basis of agreements between and/or among the parties involved.

8.2 Responsibilities of the IESO

8.2.1 The *IESO* shall classify all *SPSs* and obtain approval for their use in accordance with all applicable *reliability standards.*

8.2.2 The *IESO* shall determine the need for utilizing an *SPS* for *security* reasons.

8.2.2A The *IESO* shall direct the arming of all *SPSs* installed on the *IESO-controlled grid* in accordance with applicable *reliability standards* and applicable agreements including those negotiated under section 8.4.3.

8.2.3 The *IESO* shall direct the arming of an *SPS* to mitigate the adverse effects of specific extreme *contingency events* and to mitigate congestion provided that there are no overriding concerns related to the *security* of the *IESO-controlled grid*.

8.2.4 The *IESO* shall establish and *publish* criteria for arming and activation of *SPSs* in sufficient detail and precision to allow a *market participant* whose *facility* forms part of an *SPS* to understand the conditions under which that *SPS* would be armed and activated. Prior to establishing changes to such criteria, the *IESO* shall consult with, and, where practicable, gain the agreement of, the *market participant* whose *facility* is part of the *SPS* to the intended changes. In the event that agreement cannot be reached, the *IESO* may change the criteria for the *SPS* if necessary to maintain *reliable* operation of the *IESO-controlled grid*.

8.2.5 The *IESO* shall from time to time review or cause to be reviewed the performance of *SPSs*.

8.2.6 In the event that a *market participant* applies to the *IESO* for compensation under section 8.4.1, the *IESO* shall, upon verification that the amount being claimed is correct, pay such compensation by crediting the *market participant's preliminary settlement statement* for the last day of the month in which the application for compensation was received.

8.3 Responsibilities of SPS Equipment Owners

8.3.1 Owners of *SPS* equipment shall:

8.3.1.1 maintain *SPS* equipment in accordance with all applicable *reliability standards*;

8.3.1.2 test and report operating statistics associated with an *SPS* to the *IESO* on an annual basis;

8.3.1.3 report the performance of an *SPS* when requested to do so by the *IESO*;

8.3.1.4 evaluate and notify the *IESO* of any request from affected *market participants* for permanent exemptions from *connection* to the *SPS*; and

8.3.1.5 provide written notice to the *IESO* of any proposal to install a new, or modify an existing, *SPS*, which notice shall be provided with sufficient lead time and in sufficient detail for the *IESO* to review and seek, if necessary, approval from the relevant *standards authorities* for such new or modified *SPS*; and

8.3.1.6 specify to the *IESO* and *market participants* whose *facilities* form part of an *SPS* the means used to arm the *SPS*.

8.4 Responsibilities of Market Participants Whose Facilities Form Part of an SPS

8.4.1 A *market participant* with a *dispatchable generation facility* that is not a *quick start facility* and that is part of an *SPS* may, in the time and manner specified in the applicable *market manual*, apply to the *IESO* for compensation, if that *facility* is tripped offline as a result of the activation of the *SPS*. The amount of compensation that may be claimed shall be determined in accordance with the applicable *market manual* and shall be the equivalent of up to the first two hours of constrained off congestion management *settlement* credit payments that would otherwise be calculated if the *facility* had been constrained down to zero and its circuit breaker had remained closed.

8.4.2 Section 8.4.1 shall apply only as long as section 3.5 of Chapter 9 is in effect.

8.4.3 *Market participants* whose *facilities* form part of an existing *SPS* or may form part of a new SPS may request notification and/or status annunciation of *SPS* arming, disarming and activation and may enter into agreements with the *SPS* equipment owner/operator and the *IESO* to determine the appropriate status annunciation and notification. The *market participant*, *SPS* equipment owner/operator and the *IESO* shall use the following criteria in determining and implementing the appropriate status annunciation and/or notification:

8.4.3.1 licensing/legal requirements of the *market participant* related to the operation of its *facility* that is part of the *SPS*;

8.4.3.2 practicality of status annunciation and/or notification;

8.4.3.3 cost-effectiveness of status annunciation and/or notification;

8.4.3.4 the status annunciation and/or notification does not adversely impact the intended use of the *SPS*; and

8.4.3.5 comparison to the notification and annunciation of *SPS* arming and activation provided to other *market participants* whose *facilities* form part of an *SPS.*

In the event that they cannot agree on the status annunciation and notification requirements and implementation, the *SPS* owner/operator, the *IESO* and the *market participant* shall use the dispute resolution provisions in section 2 of Chapter 3 to resolve the issue.

8.4.4 *Market participants* whose *facilities* form part of an *SPS* shall notify the *IESO* in accordance with the applicable *market manual* or applicable agreements including those negotiated under section 8.4.3 if the *facility* is unavailable for *SPS* arming.

8.4.5 If an *SPS* has been armed and the *market participant* whose *facility* forms part of the *SPS* reasonably believes that a subsequent activation of that *SPS* would endanger the safety of any person, damage equipment or violate any *applicable law*, the *market participant* whose *facility* is part of that *SPS* may take action in accordance with applicable agreements including those negotiated under section 8.4.3 or may request that the *IESO* disarm the *SPS*. Upon such a request, the *IESO* shall, as soon as the *IESO* can take action to maintain reliable operation of the *IESO-controlled grid*, disarm the *SPS*.

9. Voltage Control

9.1 General

9.1.1 No *market participant* shall make changes in equipment status or operations that could materially adversely affect the voltage profile of the *IESO-controlled grid* without the prior approval of the *IESO*. To this end, each *market participant* shall notify the *IESO* of the *market participant's* intention to make any such change. The *IESO* shall approve such change unless it determines that the change is reasonably likely to adversely affect the *reliability* and voltage profile of the *IESO-controlled grid*.

9.2 Under Load Tap Changers

9.2.1 The *IESO* shall direct the operation of under loads tap changers installed on auto-transformers on the *IESO-controlled grid* to control the voltage profile of the *IESO-controlled grid* while ensuring that acceptable voltages at the *connections* to *IESO-controlled grid* are maintained. No *market participant* shall make any changes to such taps without the prior approval of the *IESO*. The *IESO* shall approve such changes unless it determines that such changes could affect the *IESO's* ability to control voltage on the *IESO-controlled grid*, that procedures for such changes cannot be adopted or both.

9.2A Under Load Tap Changers – Connection Transformers

9.2A.1 The *IESO* shall not direct the operation of under load tap changers on *connections* to the *IESO-controlled grid* unless, in the *IESO's* opinion, the operation of such equipment otherwise will or is likely to affect the *reliability* of the *IESO-controlled grid*.

9.3 Off Load Tap Changers

9.3.1 No *market participant* shall make any changes to off load taps of transformers on the *IESO-controlled grid* without the prior approval of the *IESO*. The *IESO* shall approve such change unless it determines that the change is reasonably likely to adversely affect the *reliability* and voltage profile of the *IESO-controlled grid*.

10. Demand Control

10.1 Introduction

10.1.1 This section 10 applies in situations on the *integrated power system* where there is insufficient capacity available to satisfy expected *demand*, where operating problems (such as frequency, voltage levels or thermal over-loads) exist which affect the ability to serve load, or where there is a breakdown on any part of the *IESO-controlled grid*. This section 10 identifies actions that the *IESO* may take or direct *market participants* to take to assist in achieving reductions in *demand* to either avoid or alleviate such situations.

10.1.2 Pursuant to Chapter 7, the *IESO* shall continuously inform *market participants* of conditions on the *IESO-controlled grid* that may require the *IESO* to initiate reductions in *demand* by *non-dispatchable loads*.

10.2 Demand Control Initiated by a Market Participant

10.2.1 *Market participants* shall notify the *IESO* of any action initiated by them to control *demand* in accordance with this section 10.2.

10.2.2 Each *market participant* that can intentionally and directly cut *dispatchable load* shall provide the following information to the *IESO*:

10.2.2.1 the proposed date, time, and duration of the cuts by *connection point* on the *IESO-controlled grid*, by hour;

10.2.2.2 the proposed MW reduction of *demand* by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.2.3 the details of the actual decrease in *dispatchable load* that was achieved.

10.2.3 Each *transmitter* and *distributor* that intends to initiate a voltage reduction shall:

10.2.3.1 by 10:00 EST each day, notify the *IESO* of all such planned voltage reductions and consequent reduction in load for the following day;

10.2.3.2 immediately notify the *IESO* of a voltage reduction that is planned after 10:00 EST for the following day;

10.2.3.3 the proposed date, time, and duration of the voltage reduction by connection point on the *IESO-controlled grid*, by hour;

10.2.3.4 the proposed MW reduction by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.3.5 details of the actual voltage reduction achieved, in MWs.

10.2.4 Each *distributor* or *transmitter* that intends to initiate a disconnection in load (including, but not limited to, interruptible loads and demand management activities) shall:

10.2.4.1 by 10:00 EST each day, notify the *IESO* of all such planned disconnections in load and consequent reduction in loads for the following day;

10.2.4.2 immediately notify the *IESO* of a disconnection in load that is planned after 10:00 EST for the following day;

10.2.4.3 the proposed date, time, and duration of the disconnection in load by *connection point* on the *IESO-controlled grid*, by hour;

10.2.4.4 the proposed reduction, in MWs, of loads by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.4.5 details of the actual reduction in loads achieved, in MWs.

10.2.5 Each *distributor* and *transmitter* that has operational control over load shall:

10.2.5.1 make arrangements that enable it to *disconnect* load immediately under an *emergency operating state* declared by the *IESO*;

10.2.5.2 make arrangements that enable it to apply *disconnections* to load to individual or specific groups of *connection points* on the *IESO-controlled grid* as determined in a coordinated fashion by the *IESO* and *market participants*;

10.2.5.3 provide the *IESO* in writing, by week 24 in each calendar year, its total forecasted peak *demand* for the immediately following twelve-month period, by *connection point* on the *IESO-controlled grid*; and

10.2.5.4 provide the *IESO* in writing, by week 24 in each calendar year, the total forecasted peak *demand* for the immediately following twelve-month period that can be *disconnected* within the following time scales: immediately, 15 minutes, 1 hour and more than 1 hour. This information shall be provided by *connection point* on the *IESO-controlled grid.*

10.2.6 No *distributor* or *transmitter* that has *disconnected* load pursuant to section 10.2.4 shall reconnect the load until directions have been received from the *IESO* permitting it to do so. Such *distributor* or *transmitter* shall commence restoration of load immediately following receipt of such directions.

10.3 Demand Control Initiated by the IESO in an Emergency Operating State

10.3.1 When an *emergency operating state* has been declared by the *IESO*, the actions available to the *IESO* to safeguard the *security* of the *IESO-controlled grid* may include issuing directions to *market participants* to reduce *demand* for electricity.

10.3.2 Whenever possible, the *IESO* shall issue a warning by 16:00 EST on the previous day when requesting a reduction of *demand* through voltage reductions or interruptions.

10.3.3 Each *market participant* that receives a direction from the *IESO* to reduce *demand* shall achieve the reduction in *demand* within 5 minutes of receipt of the direction and shall notify the *IESO* that it has done so.

10.3.4 Each *market participant* may interchange customers to whom the *demand* reduction has been applied provided the necessary *demand* reduction required by the *IESO* is achieved by the interchange.

10.3.5 No *market participant* that has reduced *demand* pursuant to this section 10.3 shall restore *demand* until directions have been received from the *IESO* permitting it to do so. Such *market participant* shall commence restoration of *demand* immediately following receipt of such directions.

10.3.6 The *IESO* shall maintain, *publish* and revise as required, following appropriate consultations with *market participants*, the *Ontario Electricity Emergency Plan* regarding exclusions to load management activities that are undertaken for the purpose of controlling *demand*.

10.3.7 The *IESO* shall release to all *market participants* an estimate of aggregate load *curtailed* as soon as practicable following the return to a *normal operating state*.

10.4 Under-Frequency Load Shedding

10.4.1 Automatic under-frequency load shedding shall be accomplished to maintain the frequency of the *IESO-controlled grid* and to restore the *IESO-controlled grid* to normal frequency following frequency deviations outside of the range established by the *IESO*.

10.4.2 Each *transmitter* shall, where possible and upon receipt of an under-frequency alarm or an indication of declining frequency and voltage, identify to the *IESO* frequency values for stations under its control.

10.4.3 Each *transmitter* shall undertake the following actions immediately and independently as pre-authorized by the *IESO* pursuant to the Operating Agreement between the *transmitter* and the *IESO*:

10.4.3.1 when frequency is between 58.5 and 59.0 Hz, take immediate independent action to shed 25% of controlled load. The block of load to be shed shall not include load connected to under-frequency load-shedding relays; or

10.4.3.2 when frequency is below 58.5 Hz, take immediate independent action to shed affected load until the frequency is restored to 59.0 Hz or, in the case of known island situations, to 60 Hz.

10.4.4 Each affected *transmitter* shall notify the *IESO* of the approximate amounts and locations of loads that were shed and of conditions on the *IESO-controlled grid*.

10.4.5 Once loads have been shed to maintain the frequency of the *IESO-controlled grid*, the *IESO* shall immediately report conditions on the *IESO-controlled grid* to affected *transmitters*.

10.4.6 Each *distributor* and *connected wholesale customer*, in conjunction with the relevant t*ransmitter*, shall make arrangements to enable the disconnection of automatic under-frequency *demand* of at least 30% of its total peak customer *demand*.

10.4.7 The *demand* of each *distributor* and *connected wholesale customer* that is subject to automatic under-frequency load shedding pursuant to section 10.4.6 shall be split into discrete MW blocks. The number, location, size and associated low frequency settings of these blocks shall be as specified by the *IESO*. Such specifications shall be established by the *IESO*, following consultations with the relevant *market participants*, by week 24 in each calendar year to cover the immediately following twelve-month period.

10.4.8 No *market participant* shall restore load that has been shed pursuant to this section 10.4 until directions have been received from the *IESO* permitting it to do so. Such *market participant* shall commence the restoration of load immediately following receipt of such direction.

10.4.9 Each *distributor* and *connected wholesale customer* shall provide the *IESO* with an estimate of the *demand* reduction that has occurred as a result of *disconnecting* under-frequency *demand*.

10.4.10 The amount of load rejected by automatic under-frequency load shedding shall conform to the minimum requirements set forth in all applicable *reliability standards.*

10.4.11 The *IESO* shall, maintain, *publish* and revise as required, following appropriate consultations with *market participants*, the applicable *market manual* regarding exclusions to load management activities that are undertaken for the purpose of shedding load during under-frequency conditions.

10.5 Generator Obligations During Abnormal Frequency

10.5.1 Abnormal frequency excursions on the *IESO-controlled grid* may require immediate actions by *generators* to restore the frequency to an acceptable level.

10.5.2 A g*enerator* that observes a frequency excursion greater than 60.2 Hz or less than 59.8 Hz shall immediately report this condition to the *IESO* and shall carry out frequency restoration actions as directed by the *IESO*.

10.5.3 No *generator* shall be precluded by the restoration actions referred to in section 10.5.2 from taking action for the purpose of protecting the safety of its equipment, its employees, the public or the environment. Any such directives shall be immediately reported to the *IESO.*

11. Emergency Preparedness and

System Restoration

11.1 Objective

11.1.1 The objective of this section 11 is to establish the means by which the *IESO* and *market participants* will fulfil their respective *emergency* preparedness and system restoration obligations, including regular and real-time testing; the preparation by the *IESO* of the *Ontario electricity emergency plan* and the *Ontario power system restoration plan*; the preparation by *market participants* of *emergency preparedness plans* that support and are coordinated with the *Ontario electricity emergency plan*; and the preparation of *restoration participant attachments* that support and are coordinated with the *Ontario power system restoration plan*. This objective will be met through co-operation and in consultation with all relevant *market participants.*

11.2 Emergency Preparedness Plans and Ontario Electricity Emergency Plan

11.2.1 The *IESO* shall develop and maintain, in consultation with all relevant *market participants*, the *Ontario electricity emergency plan* describing the responsibilities of, and coordinating the actions of, *market participants* and the *IESO* for the purpose of alleviating the effects of an *emergency* on the *electricity system,* having regard to the mitigation of the impact of an *emergency* on public health and safety as identified in each *market participant's emergency preparedness plan.*

11.2.2 The *IESO* shall file with the *Minister* the *Ontario electricity emergency plan* and such other emergency plans as the *Minister* may require pursuant to subsection 39(1) of the *Electricity Act, 1998*.

11.2.3 In order to assist the *IESO* in fulfilling its responsibilities under section 39 of the *Electricity Act*, *1998*, each *market participant* shall prepare and submit to the *IESO* an *emergency preparedness plan* and such other *emergency* preparedness-related information as the *IESO* considers necessary. Each *market participant* shall ensure that its *emergency preparedness plan* complies with section 11.2.4 and is submitted to the *IESO* during registration to become a *market participant*, or at such later times as the *IESO* shall specify.

11.2.4 Each *market participant* shall ensure that its *emergency preparedness plan*:

11.2.4.1 describes such planning, testing, information, communication and other elements designated by the *IESO*;

11.2.4.2 complies with such *emergency* planning criteria as may be designated by the *IESO*;

11.2.4.3 complies with all relevant *reliability standards*;

11.2.4.4 is consistent with the *emergency* planning and preparedness procedures established by relevant government authorities;

11.2.4.5 indicates the manner in which the impact of an *emergency* on public health and safety will be mitigated;

11.2.4.6 indicates the manner in which the *market participant* will minimize the cutting and expedite the restoration of critical loads and priority loads during short and prolonged *emergencies*; and

11.2.4.7 is submitted with a statement certified by an officer or equivalent of the *market participant* stating that the *emergency preparedness plan* is a true and complete copy as at the date of the certification.

11.2.5 The *IESO* shall assist *market participants* in the development of *emergency preparedness plans* for the purpose of ultimately establishing *emergency preparedness plans* that support and are coordinated with the *Ontario electricity emergency plan*.

11.2.6 [Intentionally left blank]

11.3 Ontario Power System Restoration Plan and Restoration Participant Attachments

11.3.1 The *IESO* shall develop and maintain, in consultation with all relevant *market participants*, the *Ontario power system restoration plan* for restoring the *security* of the *IESO-controlled grid* following a major *contingency event* or *emergency* as required by all applicable *reliability standards* and considered prudent by the *IESO* for Ontario.

11.3.2 The *Ontario power system restoration plan* shall cover each of the planning, testing, information, load reduction, load restoration, communication and other elements described in section 10 and section 11 and such other elements as the *IESO* deems necessary to implement effective system restoration.

11.3.3 The *Ontario power system restoration plan* shall include, but not be limited to:

11.3.3.1 plans for managing major disturbances on the *IESO-controlled grid* that blackout all or a portion of the *IESO-controlled grid*;

11.3.3.2 plans for the testing and verification of *emergency* preparedness facilities and procedures; and

11.3.3.3 descriptions of the roles of the IESO and various restoration participants in the Ontario power system restoration plan.

11.3.4 The *IESO* shall file with the *Minister* the *Ontario power system restoration plan* and such other restoration documentation as the *Minister* may require under subsection 39(1) of the *Electricity Act, 1998*.

11.3.5 Each *restoration participant* shall prepare and submit to the *IESO* a *restoration participant attachment* to the *Ontario power system restoration plan* and such other system restoration-related information as the *IESO* considers necessary. Each *restoration participant* shall ensure that its *restoration participant attachment* complies with section 11.3.6 and is submitted to the *IESO* during registration to become a *market participant*, or at such later times as the *IESO* shall specify.

11.3.6 Each *restoration participant* shall ensure that its *restoration participant attachment*:

11.3.6.1 includes the elements described in section 11.3.7;

11.3.6.2 complies with such restoration planning criteria as may be designated by the *IESO*; and

11.3.6.3 complies with all relevant *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

11.3.7 Each *restoration participant* shall ensure that its *restoration participant attachment* includes:

11.3.7.1 a statement describing that the *restoration participant*: (i) has an operator training program in place, (ii) uses trained operating personnel, and (iii) maintains operator training records;

11.3.7.2 documentation detailing organizational responsibility for co-ordinating with the *IESO* the development of and participation in system restoration drills. Such development and participation shall be conducted by the *restoration participant* at its own expense;

11.3.7.3 a statement describing the program in place to test the *restoration participant's* equipment as may be designated in the *Ontario power system restoration plan*. Such testing shall be conducted by the *restoration participant* at its own expense;

11.3.7.4 a statement of policy and supporting documentation demonstrating how the *restoration participant* will minimize the cutting and expedite the restoration of critical loads and priority loads under system restoration conditions;

11.3.7.5 any other documentation that the *IESO* deems necessary to support or facilitate the successful implementation of the *Ontario power system restoration plan*; and

11.3.7.6 a statement certified by an officer or equivalent of the *market participant* stating that the *restoration participant attachment* is a true and complete copy as at the date of the certification.

11.3.8 [Intentionally left blank]

11.3.9 The *IESO* shall assist *restoration participants* in the development of *restoration participant attachments* that support and are coordinated with the *Ontario power system restoration plan* for the purpose of ultimately establishing one integrated restoration plan for Ontario.

11.3.10 Each *restoration participant* shall ensure that the guidelines and procedures applicable to it and set forth in the *Ontario power system restoration plan* are carried out by trained operating staff with sufficient authority to take any action that may be necessary to ensure that all relevant equipment is operated in a timely, stable and reliable manner.

11.3.11 The *IESO* shall direct *market participants* in restoring the *IESO-controlled grid* following major disturbances. Each such *market participant* shall be responsible for carrying out these *IESO* directions, in accordance with the provisions of the *Ontario power system restoration plan.*

11.4 Review and Audit

11.4.1 The *IESO* shall review each *emergency preparedness plan* and each *restoration participant attachment* submitted to it, in accordance with sections 11.2.3 and

11.4.3, and shall prepare and provide to the relevant *market participant* or *restoration participant* a record of review indicating the changes, if any, required to be made and the date by which the revised *emergency preparedness plan* or *restoration participant attachment* must be submitted with the *IESO*.

11.4.2 Each *market participant* shall make such changes to its *emergency preparedness plan* or *restoration participant attachment* as may be required by the record of review and shall submit to the *IESO* a revised *emergency preparedness plan* or *restoration participant attachment* within the time specified in the record of review or within such other period as may be agreed with the *IESO*.

11.4.3 Each *restoration participant* shall review its *emergency preparedness plan* and *restoration participant attachment* at least annually, or as required, and shall, following such review, submit to the *IESO*:

11.4.3.1 a statement certified by an officer or equivalent of the *restoration participant* confirming that the review has not required any change to be made to its *emergency preparedness plan* or its *restoration participant attachment*; or

11.4.3.2 a revised version of its *emergency preparedness plan* or *restoration participant attachment*, amended as may be required by the results of the review, together with a statement certified by an officer or equivalent of the *restoration participant* identifying such amendments, as the case may be. Each *restoration participant* shall ensure that any revised *emergency preparedness plan* or *restoration participant attachment* prepared and submitted pursuant to this section 11.4.3 complies with section 11.2.4 or 11.3.6, respectively.

11.4.4 When directed by the *IESO*, the *market participant* shall have an independent audit of its *emergency preparedness plan* and/or *restoration participant attachment* conducted. The independent audit may be conducted by, without limitation, the *market participant's* internal auditors or before a peer review team having diverse membership or industry *emergency preparedness* expertise. The cost of conducting such an audit shall be borne by the *market participant*. Each *market participant* shall, following such audit, submit to the *IESO* a copy of the audit report, together with:

11.4.4.1 a statement certified by an officer or equivalent of the *market participant* confirming that the audit has not required any change to be made to its *emergency preparedness plan* or its *restoration participant attachment*; or

11.4.4.2 a revised version of its *emergency preparedness plan* or *restoration participant attachment*, amended as may be required by the results of the audit, together with a statement certified by an officer or equivalent of the *market participant* identifying such amendments, as the case may be. Each *market participant* shall ensure that any revised *emergency preparedness plan* or *restoration participant attachment* prepared and submitted pursuant to this section 11.4.4 complies with section 11.2.4 or 11.3.6, respectively.

11.4.5 [Intentionally left blank – section deleted]

11.4.6 The *IESO* shall review its *emergency preparedness plan*, the *Ontario electricity emergency plan* and the *Ontario power system restoration plan* at least annually, or as required. When directed by the *Minister*, the *IESO* shall have an independent audit conducted of these plans. The independent audit may be conducted by, without limitation, the *IESO's* internal auditors or before a peer review team having diverse membership or industry *emergency preparedness* expertise. The cost of such an audit shall be borne by the *IESO*.

11.4.7 [Intentionally left blank – section deleted]

11.5 [Intentionally left blank]

11.6 Emergency Facilities

11.6.1 The *IESO* may evacuate its principal control centre in the event that a circumstance arises that poses a hazard to *IESO* personnel. During and following such evacuation, operation of the *IESO-controlled grid* shall be effected in accordance with this section 11.6.

11.6.2 The *IESO-administered markets* shall continue to operate during an evacuation of the *IESO*'s principal control centre unless conditions exist that would warrant a suspension of market operations as described in Chapter 7.

11.6.3 During the interval between the evacuation of the *IESO' s* principal control centre and the establishment of a backup control centre:

11.6.3.1 the *IESO* shall designate an interim emergency system coordinator to act in its stead, as required; and

11.6.3.2 all *generators* and *transmitters* shall manage their *facilities* and support the emergency system coordinator in the operation of the *IESO-controlled grid*.

11.6.4 The *IESO* shall test the backup control centre and associated procedures and facilities on a regular basis, and each *market participant* connected to the *IESO-controlled grid* shall, at its own expense and as directed by the *IESO*, support and actively participate in evacuation tests and simulations.

11.7 Testing

11.7.1 Each *market participant* shall ensure that the capability and reliability of its personnel, procedures, and equipment are maintained to the extent necessary to fulfill its obligations under its *emergency preparedness plan* and its *restoration participant attachment*.

11.7.2 The *IESO* shall develop, schedule, implement and conduct such tests as are provided for in the *Ontario electricity emergency plan* and the *Ontario power system restoration plan.*

11.7.3 [Intentionally left blank]

11.7.4 Each *market participant* shall support and actively participate, at its own expense and as directed by the *IESO*, in the implementation and testing of its *emergency preparedness plan*, its *restoration participant attachment*, the *Ontario electricity emergency plan*, the *Ontario power system restoration plan* and voice communications facilities.

11.7.5 The *IESO* shall schedule the tests referred to in section 11.7.4 at an appropriate time of the year and time of day, in consideration of the needs of *market participants* and of the desire to minimize their costs relating to such tests. To the extent practicable, such tests of the *restoration participant attachment* shall be scheduled in a manner consistent with the *outage* coordination process described in section 6.

11.8 Enforcement

11.8.1 Failure by a *market participant* to take any action required to be taken in, or to act in a manner consistent with, its *emergency preparedness plan*, its *restoration participant attachment* or its accountabilities within the *Ontario power system restoration plan* shall be deemed to constitute a breach of the *market rules.*

12. Communications

12.1 Communication Methods

12.1.1 Communication between the *IESO* and:

12.1.1.1 market participants;

12.1.1.2 *embedded generators* required by Appendix 2.2 of Chapter 2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control or both; and

12.1.1.3 *embedded load consumers* required by Appendix 2.2 of Chapter 2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control or both,

shall take place through a combination of methods as identified in Appendix 2.2 of Chapter 2 and as directed by the *IESO* pursuant to section 12.2.3.2.

12.1.2 For the purposes of section 12.1.1 and with the exception of section 12.1.2A, the *IESO* shall provide and maintain, at its cost, a dedicated, real-time communication network from the *IESO's* facilities to the communication terminal point between such network and:

12.1.2.1 the monitoring and control devices; and

12.1.2.2 where applicable, the *dispatch workstation*

of the persons referred to in sections 12.1.1.1 to 12.1.1.3 to enable communication between the *IESO* and such persons.

12.1.2A Subject to section 12.1.6, for a *variable generator* that is a *registered market participant*, the *registered market participant* shall, if a dedicated communication network in accordance with section 12.1.2 is not already in place, provide and maintain, at its cost, a dedicated, internet based real-time communication network from the *IESO's* facilities to the communication terminal point between such network and a *dispatch workstation.* Any such internet based real-time communication network shall meet the applicable specifications and other requirements set forth in the *participant technical reference manual*.

12.1.3 The *IESO* shall provide real-time communication network channels to the persons referred to in sections 12.1.1.1 to 12.1.1.3 as follows:

12.1.3.1 one communication channel and, where available and justified for *reliable* operation of the *IESO-controlled grid* and efficient operation of the *IESO-administered markets*, a redundant physically diverse communication channel, for:

a. each *facility* to which the high performance information monitoring standard applies in accordance with Appendices 4.19 to 4.23 of Chapter 4, and

b. each *facility* that is providing monitoring information for two or more *facilities*;

12.1.3.2 one communication channel for each *facility* to which the medium performance information monitoring standard applies in accordance with Appendices 4.19 to 4.23 of Chapter 4.

12.1.3.3 [Intentionally left blank]

12.1.3.4 [Intentionally left blank]

12.1.3.5 [Intentionally left blank]

12.1.4 The *IESO* may, in respect of a given *facility*, provide additional real-time network communication channels in addition to those referred to in section 12.1.3 where the *IESO* considers, based on the size and location of the *facility*, and, where applicable, the number of *facilities* monitored at a single *facility*, that such additional channels are desirable for purposes of maintaining the *reliability* of the *IESO-controlled grid*.

12.1.5 Where a *market participant* wishes to submit *dispatch data*, *physical bilateral contract data*, or *TR bids* or *TR offers* in the *TR market* using private network dedicated communication links, all costs associated with such use, including but not limited to the cost of the provision and maintenance of the required communication channel, shall be borne by the *market participant*.

12.1.6 Where problems exist which require methods of communication other than those referred to in section 12.1.1 or 12.1.2A, such alternative communication capabilities as shall be selected by the *IESO*, including facsimile capability, shall be used.

12.2 Voice Communication

12.2.1 [Intentionally left blank]

12.2.2 [Intentionally left blank]

12.2.3 Each market participant, embedded generator and embedded load consumer shall provide and maintain:

12.2.3.1 the applicable voice communication facilities required by Appendix 2.2 of Chapter 2 and that meet the requirements of that Appendix; and

12.2.3.2 such additional or other voice communication facilities as the *IESO* may direct in respect of *facilities* that the *IESO* considers to be significant for purposes of maintaining the *reliability* of the *IESO-controlled grid*.

12.2.4 Each person referred to in section 12.2.3 shall ensure that the overall mean time between failures of the voice communication facilities referred to in section 12.2.3 is no less than five years.

12.2.5 Each person referred to in section 12.2.3 shall respond to an outage of or defect in the voice communication facilities referred to in section 12.2.3:

12.2.5.1 immediately, in the case of an outage of or defect in a *high priority path facility*; and

a. [Intentionally left blank]

b. [Intentionally left blank]

c. [Intentionally left blank]

d. [Intentionally left blank]

e. [Intentionally left blank]

f. [Intentionally left blank]

g. [Intentionally left blank]

12.2.5.2 no later than the next day following the day on which the outage or defect is discovered, in the case of an outage of or defect in a *normal priority path facility.*

a. [Intentionally left blank]

b. [Intentionally left blank]

c. [Intentionally left blank]

d. [Intentionally left blank]

e. [Intentionally left blank]

f. [Intentionally left blank]

12.2.6 Each person referred to in section 12.2.3 shall ensure that the voice communication facilities referred to in section 12.2.3 are restored to a fully operational state following an *outage* of or defect in such facilities as follows:

12.2.6.1 in the case of the *high priority path facilities* referred to in section 12.2.5.1, within 24 hours of the time at which the *outage* or defect is discovered;

12.2.6.2 in the case of the *normal priority path facilities* referred to in section 12.2.5.2, within 48 hours of the time at which the *outage* or defect is discovered; and

12.2.6.3 in all other cases, within 14 days of the time at which the *outage* or defect is discovered.

12.2.7 The *IESO* may direct a person referred to in section 12.2.3 to respond and restore a voice communication facility to a fully operational state following an *outage* of or defect in such facility within such longer or shorter time periods than those referred to in sections 12.2.5 and 12.2.6 based on the immediate or short-term impact of the unavailability of the voice communication facility on the *reliable* operation of the *IESO-controlled grid*.

12.2.8 Each person referred to in section 12.2.3 shall notify the *IESO* of any *planned outage* of the voice communication facilities referred to in section 12.2.3 no less than four days prior to the *planned outage*.

12.2.9 The *IESO* shall:

12.2.9.1 maintain, at each of its principal control center and back-up control center, *high priority path facilities* and *normal priority path facilities* that meet the requirements of sections 1.1.7 and 1.1.8 of Appendix 2.2 of Chapter 2, respectively, for the purpose of voice communication with the persons referred to in section 12.2.3 and with neighbouring *security coordinators*; and

12.2.9.2 ensure that its voice communication facilities include facilities that permit telephone conference calls between six parties.

12.2.10 The *IESO* shall develop, in consultation with all relevant *market participants*, test plans and procedures for voice communication during an *emergency* on or a major disturbance of the *IESO-controlled grid*.

12.2.11 Each person referred to in section 12.2.3 shall, at its own expense, not less than annually or more frequently as may be directed by the *IESO*, monitor and test its voice communication facilities and shall, at its own expense and as directed by the *IESO*, support and actively participate in the testing of voice communication facilities.

12.2.12 Where problems exist which require methods of communication other than those referred to in section 12.2.3, such alternative communication capabilities as shall be selected by the *IESO*, including facsimile capability, shall be used.

12.3 Electronic Data

12.3.1 *Energy* management system (EMS) information shall be exchanged between the communication system of the *IESO* and the communication system of each *market participant* in order to support real-time functions such as:

12.3.1.1 the monitoring of the *IESO-controlled grid*;

12.3.1.2 the control and analysis of *generation facilities*;

12.3.1.3 an analysis of the *security* of the *IESO-controlled grid*;

12.3.1.4 the scheduling of *generation facilities*;

12.3.1.5 the monitoring of compliance with *dispatch instructions*; and

12.3.1.6 [Intentionally left blank]

12.3.1.7 reports.

12.3.2 The *IESO* and *market participants* shall exchange EMS information between their respective communication systems via dedicated data circuits.

12.3.3 For the exchange of schedules referred to in Chapter and of *outage* and planning data between *market participants* and the *IESO*, a computer path distinct from the EMS path shall be used. Communications shall occur over separate data links using a different protocol than that used for EMS information. Real-time *dispatch instructions* for *generation facilities*, transmission *facilities* and load shall be communicated electronically through the EMS path and shall be integrated with the EMS messaging system for logging purposes.

12.4 Voice Links and Other Communications

12.4.1 The *IESO* shall develop and notify all *market participants* of standard operating terms, abbreviations and definitions that shall be approved for use in communications between the *IESO* and *market participants*. Such approved, standard operating terms, abbreviations and definitions shall wherever possible be used by the *IESO* and *market participants* in their communications with one another.

12.4.2 All communications between a *market participant* and the *IESO* with respect to the *reliability* of the *IESO-controlled grid* shall be recorded and the records shall be retained by the *IESO* for 7 years.

12.4.3 The *IESO* shall maintain a log of activities related to the *reliable* operation of the *IESO-controlled grid.*

13. Prior Arrangements

13.1 Market Participant Review of Arrangements

13.1.1 Each *market participant* shall review any contractual or other arrangements relating to the *reliability* of the *IESO-controlled grid* which it may have with other *market participants* or with *interconnected systems* on the date of coming into force of this Chapter for the purpose of determining whether such arrangements are consistent with the requirements of, or the obligations imposed on the *market participant* by, this Chapter. Where such contractual or other arrangement is consistent with the requirements and obligations imposed on the *market participant* by this Chapter, no further action with respect to such contract or arrangement is required.

13.1.2 Where a *market participant* determines that a contractual or other arrangement referred to in section 13.1.1 is inconsistent with the requirements of, or the obligations imposed on the *market participant* by, this Chapter, the *market participant* shall:

13.1.2.1 negotiate an amendment to the contract or a modification to the arrangement which removes the inconsistency; or

13.1.2.2 report the inconsistency to the *technical panel*, which shall make a determination as to whether the inconsistency will or is reasonably likely to have an adverse effect on the *reliability* of the *IESO-controlled grid*.

13.1.3 Where the *technical panel* determines under section 13.1.2 or 13.1.4 that the inconsistency will or is reasonably likely to have an adverse effect on the *reliability* of the *IESO-controlled grid*, the *IESO* shall take appropriate actions to mitigate the effect of the inconsistency until the inconsistency is removed.

13.1.4 Where the *IESO* becomes aware that a contractual or other arrangement referred to in section 13.1.1 is inconsistent with the requirements of, or the obligations imposed on a *market participant* by, this Chapter, it may report the inconsistency to the *technical panel* notwithstanding that the inconsistency may not have been reported by the *market participant* and the *technical panel* shall make the determination referred to in section 13.1.2.2 in respect of that inconsistency.

14. Information and Reporting Requirements

14.1.1 The *reliable* operation of the *IESO-controlled grid* requires the rapid and continuous flow of accurate information among the *IESO*, *market participants* and *interconnected systems*, with due regard for maintaining the confidentiality of information where appropriate. To that end, the *IESO* shall establish and periodically up-date and inform all *market participants* with respect to the specific information it requires from *market participants* for *reliability* purposes.

14.1.2 Each *market participant* shall provide the information referred to in section 14.1.1 to the *IESO* in the manner and within the time prescribed by the *IESO*. By submitting such information to the *IESO*, a *market participant* is considered to have fulfilled any requirement under a *reliability standard* to report such information to one or more *standards authorities*. The *IESO* shall provide such information to other *standards authorities*, as required.

14.1.3 The *IESO* shall establish a catalogue of reporting requirements listing the *reliability*-related information to be exchanged between the *IESO* and *market participants.* Such reporting requirements shall include, but not be limited to, the following:

14.1.3.1 each *market participant* shall report to the *IESO* the planned implementation of a change to a setting on a fixed-tap transformer. This information shall be reported to the *IESO* in writing one week prior to the date scheduled for implementation of such change, provided that where such change is effected on an unplanned, emergency basis, the information shall be reported to the *IESO* within one *business day* of implementation of the change;

14.1.3.2 each *market participant* shall report to the *IESO* any change in equipment and *facilities* to that which has been provided pursuant to Chapter 4;

14.1.3.3 each *market participant* shall report to the *IESO* a list of all of its equipment for which periodic maintenance has been performed on *special protection systems* in the previous 12 months, as required by relevant *standards authorities*. This information shall be reported no later than the first day of December in each year;

14.1.3.4 each *market participant* shall provide to the *IESO* a report describing any modification proposed to be made to protection on a primary relay. The report shall be delivered to the *IESO* within one week of the date on which the *IESO* approves such modification pursuant to section 6 of Chapter 4, or, where the modification is effected on an unplanned, emergency basis, within one week of the date of modification;

14.1.3.5 each *market participant* shall annually provide to the *IESO* a written summary of actions taken to control *demand* in the previous 12 months;

14.1.3.6 each *market participant* shall annually provide to the *IESO* a written summary of automatic under-frequency load shedding activities taken in the previous 12 months; and

14.1.3.7 each *market participant* shall annually provide to the *IESO* a report of *reliability*-related performance measures for transmission *facilities* and *connections* to the *IESO-controlled grid* in accordance with all applicable *reliability standards*.

14.1.4 Each *market participant* shall provide to the *IESO* such data as may be required by the *IESO* to enable it to satisfy a request by a *standards authority.*

14.1.5 The *IESO* shall file such reports including, but not limited to, disturbance reports, and participate in such discussions as may be required by relevant *standards authorities*. Each *market participant* shall provide to the *IESO* such information and reports as may be required by the *IESO* to facilitate preparation by the *IESO* of such disturbance reports.

PLAN

Market Manual 7: System Operations

Part 7.10: Ontario Electricity Emergency Plan

Issue 7.0

This document describes the Ontario electricity sector's emergency management program, and how the IESO coordinates with market participant and government stakeholders.

Disclaimer

The posting of documents on this Web site is done for the convenience of *market participants* and other interested visitors to the *IESO* Web site. Please be advised that, while the *IESO* attempts to have all posted documents conform to the original, changes can result from the original, including changes resulting from the programs used to format the documents for posting on the Web site as well as from the programs used by the viewer to download and read the documents. The *IESO* makes no representation or warranty, express or implied, that the documents on this Web site are exact reproductions of the original documents listed. In addition, the documents and information posted on this Web site are subject to change. The *IESO* may revise, withdraw or make final these materials at any time at its sole discretion without further notice. It is solely your responsibility to ensure that you are using up-to-date documents and information.

This *market manual* may contain a summary of a particular *market rule*. Where provided, the summary has been used because of the length of the *market rule* itself. The reader should be aware, however, that where a *market rule* is applicable, the obligation that needs to be met is as stated in the "Market Rules". To the extent of any discrepancy or inconsistency between the provisions of a particular *market rule* and the summary, the provision of the *market rule* shall govern.

Document ID	IMO_PLAN_0002
Document Name	Part 7.10: *Ontario Electricity Emergency Plan*
Issue	Issue 7.0
Reason for Issue	Issue released for Baseline 30.1
Effective Date	December 4, 2013

Document Change History

Issue	Reason for Issue	Date
1.0	First release, *IESO* Board approval	June 2, 2000
2.0	Review and revised after Exercise 2002	November 20, 2002
3.0	General review and revised to incorporate lessons learned from Blackout 2003 and Exercises 2003 and 2004. Market Participant Emergency Planning Criteria and Electricity Emergency Priority Policy documents incorporated into this document. Endorsed by EPTF.	May 26, 2005
4.0	Extensive re-write to more fully describe the scope of the *Ontario Electricity Emergency Plan* and the role of *market participants*. Re-structured to more closely align with the Canadian Standards Association's new Emergency Management and Business Continuity standard CSA Z1600. Now written as Market Manual 7.10 to conform with the *IESO*'s documentation hierarchy. Endorsed at May 20, 2009 stakeholder Emergency Preparedness Task Force meeting. Issue released for Baseline 22.0	September 9, 2009
5.0	Various updates throughout including: • Removal of Priority 2 Customer Load and adding electrically-driven gas pipeline compressors to the list of Priority Customer Loads examples in the Critical Power System and Priority Customer Load table; • A number of changes to reflect the CMST's Guiding Principles; and • Updates to the CMST and EPTF rosters. Issued for Baseline 25.1	June 1, 2011
6.0	Changes throughout to reflect an All Hazards Approach Issue released for Baseline 27.0	March 7, 2012
7.0	Industrial Consumer load shedding planning guidance added. Emergency Preparedness Plan requirements examples added for market participant guidance.	December 4, 2013

Related Documents

Document ID	Document Title
MDP_PRO_0040	System Operations Manual 7.1 - System Operating Procedures Manual
IMO_PLAN_0001	Market Manual Part 7.8 - *Ontario Power System Restoration Plan*
IMO_MAN_0001	Emergency Drills and Exercises Guide
IMO_GDE_0001	Market Participant Emergency Planning Guidelines
	Canadian Standards Association's Emergency Management and Business Continuity standard CSA Z1600
	Canadian Standards Association's Emergency Management and Business Continuity standard CSA Z731
	Emergency Management Glossary of Terms (Interim) 2011
	Ontario Provincial Hazard Identification and Risk Assessment Report ("HIRA")

Table of Contents

Table of Changes

Reference (Section and Paragraph)	Description of Change
Section 4.4.2	Added new section to provide additional load shedding planning guidance for Industrial Consumers.
Section 4.6.1 and 4.6.2	Added examples to provide additional planning guidance to market participants for emergency preparedness plan requirements.
Appendix B	Added Enbridge Gas and Union Gas to the CMST roster and their responsibilities upon CMST activation.

1. Executive Summary

This *Ontario Electricity Emergency Plan* (OEEP) describes the coordinated actions required of the Independent Electricity System Operator (*IESO*) and *market participants* to plan for and respond to emergencies affecting the reliable supply of electricity to Ontario. It supports the principles outlined in the Ontario government's Provincial Emergency Response Plan (PERP).

The OEEP:

- Describes how we meet the emergency planning requirements of the *Electricity Act (1998)* and the *market rules.*
- Provides the framework for how we plan for and respond to threats, incidents, or emergency situations among the *IESO*, *market participants*, the Ministry of Energy (MoE), and Emergency Management Ontario (EMO) within the Ministry of Community Safety and Correctional Services.
- Describes how we collaborate to test and exercise our plans, and take corrective actions in a spirit of continuous improvement.

– End of Section –

2. About This Manual

This document is Part 7.10 – *Ontario Electricity Emergency Plan* of the *IESO* Market Manual 7 – System Operations.

2.1 Purpose

The OEEP describes:

- The emergency planning requirements of the *IESO* and *market participants*, and
- How the *IESO* and *market participants* work together to coordinate their emergency planning and response activities

2.2 Scope

Electricity is perhaps the most critical of infrastructures that support our way of life both at home and at work. This OEEP describes the overall framework for how Ontario's electricity sector coordinates its emergency planning and responds to situations, events, or incidents affecting electricity *reliability*.

The OEEP:

- Describes the coordinated actions required of the *IESO* and *market participants* to plan for and respond to emergencies affecting the reliable supply of electricity to Ontario
- Describes how to meet the emergency planning requirements of the *Electricity Act, 1998* and the *market rules*
- Supports the principles outlined in the PERP
- Establishes the framework to share information related to situation assessments and recovery strategies among *market participants*, the Independent Electricity System Operator (*IESO*), the Ministry of Energy (MoE), Emergency Management Ontario (EMO), and Public Safety Canada (PS)

The OEEP focuses on emergencies affecting a large segment of Ontario's power system with the potential for significant adverse impact on public health and safety, or economic disruption. Typically, such an event would also affect *market participants* or jurisdictions outside Ontario, and would involve senior management and government officials to return the situation to normal.

Examples include events such as the 1998 ice storm and the August 2003 blackout. In addition to providing the overall framework for responding to these types of significant events, the OEEP takes an all-hazards, all-threats approach that includes physical and cyber security, and what has become known in recent years as critical infrastructure protection.

The OEEP requires the electricity sector to be prepared to respond to all hazards affecting grid reliability, and it recommends that all *market participants* also be prepared to respond to hazards to their own operations and businesses. The OEEP adopts the EMO list of Hazards for operations in Ontario, and recommends that *market participants* consider corresponding local hazards for critical supplies, equipment, and services sourced from other jurisdictions.

The OEEP is consistent with the program elements laid out in the Canadian Standards Association's Z1600-08 Emergency Management and Business Continuity program, and addresses program management, planning, implementation, evaluation, and management review.

2.3 Who Should Use This Manual

The OEEP provides context for all *market participants* and government stakeholders with roles in emergency preparedness. It describes how Ontario's electricity sector coordinates actions to support a timely and coordinated response to any emergency affecting the supply and delivery of electricity to *consumers*.

2.4 Conventions

Conventions for this market manual:

- 'We' means the *IESO* and *market participants*
- 'Program' means the initiatives and actions the *IESO* takes in collaboration with *market participants* and government officials to help ensure our *emergency preparedness plans* and response are coordinated and effective
- 'Grid' means the *IESO-controlled grid*
- Italicized words have meanings ascribed to them in Chapter 11 of the market rules.

2.5 List of Acronyms

AMPCO	Association of Major Power Consumers of Ontario
BOMA	Building Owners and Managers Association
CIP	Critical Infrastructure Protection
CMCC	Crisis Management and Communications Centre
CMST	Crisis Management Support Team
EDA	Electricity Distributors Association
EIC	Emergency Information Centre
EMO	Emergency Management Ontario
EPTF	Emergency Preparedness Task Force
IESO	Independent Electricity System Operator
MoE	Ministry of Energy
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEEP	*Ontario Electricity Emergency Plan*
OPG	Ontario Power Generation
OPSRP	*Ontario Power System Restoration Plan*
PEOC	Provincial Emergency Operations Centre
PERP	Provincial Emergency Response Plan
PNERP	Provincial Nuclear Emergency Response Plan
PS	Public Safety Canada
THES	Toronto Hydro-Electric System

– End of Section –

3. Program Management

This section describes how the *IESO*'s emergency management program is organized and managed, and how it is enhanced by the active contribution and cooperation of *market participants*.

3.1 Leadership and Commitment

This OEEP assumes that senior leaders and qualified staff from the *IESO*, *market participants*, and government are actively involved in this program, and adequate resources are made available.

A successful emergency management program includes continuous improvement. Even the best plans need to be exercised regularly through simulations and real events. Exercise scenarios must be realistic, yet imaginative, to challenge responders to expect the unexpected. Implementing the lessons-learned from such exercises ensures the currency and effectiveness of our collective capability to manage electricity system emergencies.

3.2 Program Coordinator

Section 39 of the *Electricity Act, 1998* designates the *IESO* as the overall coordinator of Ontario's electricity emergency management program. To meet this obligation, the *IESO*'s Chief Operating Officer chairs the stakeholder-represented Emergency Preparedness Task Force (EPTF) for planning initiatives, and the Crisis Management Support Team (CMST) for response actions.

3.3 Advisory Committee

In 1998, the electricity industry in Ontario faced a number of challenges that prompted us to improve how we coordinate our emergency planning activities. A recent ice storm had plunged much of Eastern Ontario and Quebec into darkness. In some areas it took several weeks before power was restored. Y2K was approaching, and although the industry had expended much time and effort to ensure computer systems would support the roll-over into 2000, we needed contingency plans to support rapid response and recovery should the unexpected occur.

As well, the *Electricity Act, 1998* split Ontario Hydro into several successor organizations. The Act established the framework for a restructured Ontario electricity sector to support a competitive wholesale electricity market composed of hundreds of separate companies in their roles as transmitters, local *distribution* companies, generators, wholesale *consumers*, and traders. This new structure required close coordination at all times, especially during emergency situations. While the Act has undergone several revisions over the years, the provisions for emergency plans (section 39) have stood the test of time and real events, including the August 2003 Blackout[1].

Therefore, the *IESO* established the stakeholder-represented EPTF to help coordinate Ontario's electricity sector emergency planning activities.

The electricity industry is diverse, and we have learned from experience there is great benefit in working together to address emergency management matters. The EPTF plays an important role by

[1] Ontario's Premier declared a Provincial Emergency in response to the August 2003 Blackout.

providing a forum for participants to share information and approaches to address emergency management issues, and to provide input and advice to the *IESO*. The *IESO* and all *market participants* are responsible for maintaining their own company's emergency management program that addresses their own needs, and supports this coordinated approach.

The current roster of EPTF participants is in Appendix A.

3.3.1 Market Participant Involvement

The EPTF benefits from broad and inclusive participation of all types of *market participants* – generators, transmitters, local distribution companies, and industrial and commercial *consumers*. It is important that stakeholder representatives on the EPTF have accountability and senior management support from their own organizations for emergency management matters.

EPTF participants provide input on behalf of their organizations in the context of our mutual goal of minimizing the impact of electricity emergencies on public health and safety and the economy. EPTF participants benefit by helping ensure our planning and exercise initiatives are effective and are of value to their own organizations. Participants are also able to keep abreast of developments within Ontario and abroad.

While all *market participants* are welcome to participate on the EPTF, those who have a greater impact on electricity *reliability* (especially *market participants* who are *restoration participants*[2]) are encouraged to participate on a regular and sustained basis. Others may participate periodically – for example, to plan and participate in workshops and exercises, or identify lessons from real events.

While we need some face-to-face meetings to build strong collaborative relationships, we also try to minimize travel time and costs by using conference calls and the web to share information and encourage stakeholder participation. The *IESO*'s public web site provides an overview of our emergency management program, and a password-secured web site to coordinate the EPTF's work program with participants.

3.3.2 Government Involvement

Government representatives from MoE, EMO and PS are also key stakeholders on the EPTF. The EPTF provides an important forum to ensure that the OEEP and the EPTF's activities are consistent with the PERP. The EPTF also serves as the Electricity Sector Working Group under the provincial government's Critical Infrastructure Assurance Program.

3.4 Program Administration

The *IESO* chairs the EPTF and provides support to organize meetings, draft agendas, prepare minutes, and produce reports. An EPTF Work Plan, that addresses each of the program elements under the CSA's Z1600 standard, provides the planning framework for the EPTF's initiatives over the next two years. The EPTF meets at least quarterly, and participants take turns hosting the meetings.

Periodically, we establish subordinate working groups to take on specific EPTF initiatives. Subject matter experts from various participants provide the knowledge and experience needed, for example, to:

[2] The *IESO* identifies "Restoration participants" using the criteria in Section 3 of the *Ontario Power System Restoration Plan*. In general, they are *market participants* who own or operate the assets needed to restore Ontario's grid in the event of a large-scale system blackout.

- Plan and coordinate workshops and exercises
- Review and revise the *Ontario Power System Restoration Plan*
- Share information related to cyber security
- Develop emergency planning guidance documents

3.4.1 Program Goals and Objectives

The goal of Ontario's electricity emergency management program is to coordinate the efforts of the *IESO* and *market participants* to prevent or mitigate incidents that could affect the reliable supply of electricity and threaten people, property, or the environment.

To achieve this goal, the emergency management program's objectives are to:

- Provide a forum to encourage and facilitate information-sharing among participants
- Provide subject matter expertise to identify and address hazards and threats to Ontario's *electricity system*
- Carry out work programs to improve our overall readiness to anticipate and respond
- Inform, advise, and support *market participants* and government

3.4.2 Program Plan and Procedures

The EPTF prepares a 2-year work plan annually that is endorsed by participants at the EPTF's first meeting of the year. Program areas include each of the elements in the CSA Z1600 standard:

- Program management
- Planning
- Implementation
- Exercises
- Evaluations and corrective actions
- Management review

We review the status of the work plan at each EPTF meeting to ensure work is on-track and to consider if we need to revise or re-prioritize plans.

The EPTF recognizes that the work plan may need to change significantly to respond to real events. For example, immediately following the August 2003 blackout, we established a restoration working group to detail the sequence and timing of restoration efforts in Ontario, recommend areas for improvement, and reinforce what went well.

3.4.3 Program Budget

The *IESO* commits resources to support the maintenance and implementation of the OEEP through its business planning process. The *IESO*'s business plan is approved by the Minister of Energy and the Ontario Energy Board, and is available on the *IESO*'s public web site.

As described above, the success of Ontario's electricity emergency management program depends heavily on the contribution of *market participants*. While *market participants* contribute to the work of the EPTF at their own expense, the *IESO* strives to ensure that EPTF activities are well-organized, effective, and continue to evolve according to need.

3.4.4 Program Review

At each EPTF meeting, actions are tracked against expected completion dates. At the last meeting of each year, the EPTF work plan is reviewed from a strategic perspective to determine if program areas or resources need to change which are then reflected in next year's work plan. As part of its compliance monitoring and enforcement activities, *NERC* audits the *IESO*'s program against *reliability* standards.

3.5 Laws and Authorities

The *Electricity Act, 1998*, and the *market rules* provide the "policies" for emergency planning in Ontario's electricity sector and set out the legal requirements. The *market rules* describe the obligations of the *IESO* and all *market participants*, supported by a compliance monitoring function that reports directly to the *IESO*'s President and Chief Executive Officer.

The *Electricity Act, 1998, Section 39*, designates MoE and the *IESO* as the organizations responsible for emergency planning among *market participants* and assuring that electricity emergencies can be coordinated effectively.

Section 39 of the Act states:

1 The Minister shall require the IESO to prepare and file with the Minister such emergency plans as the Minister considers necessary

2 The Minister may require a Market Participant to prepare and file with the Minister such emergency plans as the Minister considers necessary

3 The IESO shall assist in coordinating the preparation of plans under subsections (1) and (2)

4 The Minister may direct the IESO or a Market Participant to implement an emergency plan filed under subsection (1) or (2), with such changes as the Minister considers necessary

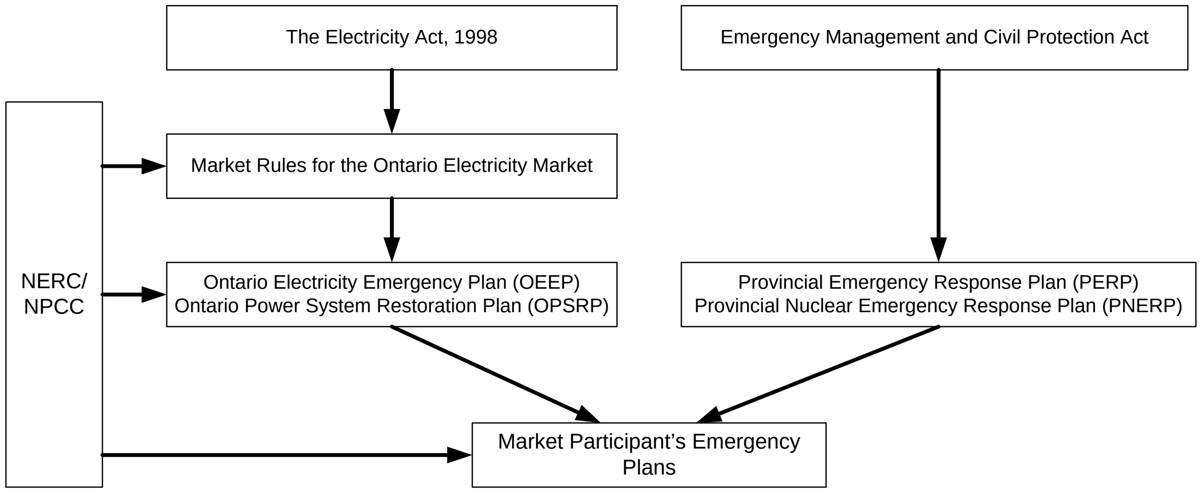
5 Every generator that owns or operates a nuclear generation facility shall file with the Minister a copy of any emergency plans relating to the facility that are filed with the Canadian Nuclear Safety Commission.

To meet this legal requirement, Chapter 5, Section 11 of the *market rules* describes the Emergency Preparedness and System Restoration requirements of the *IESO* and *market participants*:

- All *market participants* are required to maintain *emergency preparedness plan*s, and submit them to the *IESO* for review
- In addition, *restoration participants* are required to prepare *restoration participant* attachments, and submit them to the *IESO* for review

These *market rule* requirements are consistent with *NERC* emergency operations (EOP) standards.

The Emergency Management and Civil Protection Act includes the provision that the Minister of Community Safety and Correctional Services may formulate plans respecting emergencies. This need is fulfilled by the PERP, and the PNERP. While the PERP does not specifically apply to non-government entities, the OEEP is intended to support the goals of the PERP. On the other hand, the PNERP does place requirements on owners and operators of nuclear facilities in Ontario. Therefore, to ensure optimal coordination, *market participants* who own or operate nuclear facilities need to keep the *IESO* advised of any changes to the PNERP that could be relevant to the OEEP.



3.5.1 Compliance

The *IESO*'s Reliability Compliance Program monitors *IESO* and market participant compliance with the market rules. The *IESO* may request that a *market participant* perform an independent audit of its own plans, and provide the results to the *IESO*. The *IESO*'s plans are subject to audit by the NPCC against *NERC* standards.

Market participants who breach the *market rules* may be subject to sanctions if the *IESO* considers it appropriate, given the circumstances. These sanctions could be a directive instructing the *market participant* to rectify a breach of the *market rules*, financial penalties, suspension, or termination from the market, depending on the nature of the breach or instance of non-compliance.

3.5.2 Non-regulatory Initiatives

While industry standards and mandatory compliance mechanisms are useful, not all aspects of a comprehensive and effective emergency management program lend themselves to "regulation". Regulatory processes can be inflexible, overly prescriptive, slow to change, and can stifle innovative solutions. Threats and hazards that face the industry today are ever-changing. The spirit of the OEEP for the *IESO* and all *market participants* is to understand the risks we face and keep those risks at an acceptable level.

– End of Section –

4. Planning and the EPTF

This section describes our emergency planning framework, which takes a risk management approach to ensure planning requirements and EPTF initiatives are comprehensive, effective and reasonable.

4.1 Key Definitions

When discussing elements of an All Hazards approach with other emergency management professionals it is important to have a consistent understanding of each of the terms. For the purposes of consistency the EPTF has adopted the EMO definitions as provided in the "Emergency Management Glossary of Terms (Interim) 2011".

- **Hazard :** An event or physical condition that has the potential to cause fatalities, injuries, property damage, infrastructure damage, interruption of business, or other types of harm or loss;
- **Risk:** A chance or possibility of danger, loss, injury, or other adverse consequences. The concept of risk requires a determination of the probability of an incident occurring and the consequences of the occurrence;
- **Threat:** Any event that has the potential to disrupt or destroy critical infrastructure, or any element thereof. Threat includes accidents, natural hazards as well as deliberate attacks;
- **Vulnerability:** the degree of susceptibility and resilience of the organization and environment to hazards, the characteristics of a system in terms of its capacity to anticipate, cope with and recover from events; and
- **Incident:** An occurrence or event that requires an emergency response to protect life, property, or the environment.

4.2 Threat and Hazard Identification

Threats and hazards that may affect the *reliability* of Ontario's *electricity system* include natural, technological, and human-caused events. The *IESO* and *market participants* need to be aware of how these risks are changing, from both a local and global perspective. The OEEP has adopted Emergency Management Ontario's list of hazards from the Ontario Provincial Hazard Identification and Risk Assessment Report or "HIRA" as depicted in the table below.

Technological Hazards:
Building/ Structural Collapse
Critical Infrastructure Failure
Dam Failure
Energy Supply Emergencies
Explosions/ Fires
Hazardous Materials Incident
Human-Made Space Object Crash
Mine Emergencies
Nuclear Facility Emergencies
Oil, Natural Gas Emergencies
Radiological Emergencies
Transportation Emergencies

Human-Caused Hazards:
Civil Disorders
Cyber Attack
Sabotage
Special Events
Terrorism/CBRNE
War/International or Provincial/Territorial Emergency
Financial/Economic Crisis*

Natural Hazards:
Agriculture and Food Emergencies
Drinking Water Emergency
Drought/Low Water
Earthquake
Erosion
Extreme Heat/Cold
Flood
Fog
Forest/Wildland Fire
Freezing Rain
Geomagnetic Storm
Hailstorms
Human Health Emergency
Hurricanes/ Tropical Storms
Land Subsidence
Landslide
Lightning Storms
Natural Space Object Crash
Snowstorm/Blizzard
Tornado
Windstorm

* Note: Financial/Economic Crisis is not on the EMO list, and has been added here. The impacts of this hazard to the electricity sector are: 1) an underinvestment in infrastructure; and 2) companies going out of business.

Table 4-1: EMO List of Hazards

The EPTF plays a valuable role by providing a forum of experts who monitor these ever-changing threats and hazards, and share information promptly in order to understand likelihood, potential impacts, and to initiate any necessary action.

4.3 Risk Assessment

We need to assess threats and hazards to determine the likelihood and potential impact on electricity infrastructure, people, property and the environment.

Given the large number and great diversity of *market participants* in Ontario, individual risk assessments may vary widely, and should ensure that risks resulting from all hazards to business and operations are assessed. It is important to also perform a risk assessment from an integrated *electricity system* perspective regarding grid reliability as a whole. The *IESO* and *market participants* use these risk assessments to determine their own ability to maintain electricity *reliability* and take any necessary operational actions. The EPTF plays an important role by providing input and advice to the *IESO* in preparing these risk assessments.

While many different risk assessment methodologies are available, many are complex or best-suited to specific applications. For the purposes of the EPTF, we have found that a simple, qualitative model meets our needs. A "commonly used approach to risk management"[3] takes the following steps:

1. Identification of assets and loss impacts.
   - 1.1 Determine the critical assets that require protection.
   - 1.2 Identify possible undesirable events
   - 1.3 Prioritize the assets based on consequence of loss.
2. Identification and characterization of the threat
   - 2.1 Identify threat categories and potential adversaries.
   - 2.2 Assess intent and motivation of the adversary.
   - 2.3 Assess capability of adversary or threat.
   - 2.4 Determine frequency of threat-related incidents based on historical data.
   - 2.5 Estimate degree of threat relative to each critical asset and undesirable events.
3. Identification and analysis of vulnerabilities using a realistic threat
   - 3.1 Identification and analysis of vulnerabilities using a realistic threat.
   - 3.2 Identify potential vulnerabilities related to specific assets or undesirable events.
   - 3.3 Identify existing countermeasures and their level of effectiveness in reducing vulnerabilities.
   - 3.4 Estimate the degree of vulnerability relative to each asset.
4. Assessment of risk and the determination of priorities for the protection of critical assets
   - 4.1 Estimate the degree of impact relative to each critical asset.
   - 4.2 Estimate the likelihood of an attack by a potential adversary.
   - 4.3 Estimate the likelihood that a specific vulnerability will be exploited. The estimate can be based on factors such as prior history or attacks on similar assets, intelligence, and warning from law enforcement agencies, consultant advice, the company's own judgment, and additional factors.
   - 4.4 Prioritize risks based on an integrated assessment.
5. Identification of risk reduction measures, costs and trade-offs.
   - 5.1 Identify potential countermeasures to reduce the vulnerabilities.
   - 5.2 Identify potential facility changes that reduce the consequences from an event
   - 5.3 Estimate the cost of the countermeasures.
   - 5.4 Conduct a cost-benefit and trade-off analysis.

[3] Ref. "Risk Assessment Methodologies for Use in the Electric Sector", North American Electric Reliability Corporation

4.4 Operational Impact Assessment

The grid is designed and operated to respond to *contingency events* that may occur without notice at any time. System operators are trained to manage the impact of unanticipated equipment failures, and to respond to changes in demand while maintaining electricity *reliability*. The vast majority of these contingencies are managed without any disruption of supply to *consumers*, as part of everyday business. By building on this capability, we are well-positioned to evaluate and respond to more unusual events that could have a very significant impact on *reliability*.

Ontario's residential, commercial and industrial *consumers* are served by one of the most reliable *electricity system* in the world. Under normal conditions, they enjoy a virtually uninterrupted supply of electricity, and there is no need to prioritize delivery to one *consumer* over another. However, under emergency conditions, it becomes critically important to be able to prioritize quickly and effectively under very challenging circumstances.

The following definitions provide a framework to ensure that *market participants* make the difficult decisions regarding priorities before an emergency occurs. They also ensure that overall system needs that benefit large portions of Ontario are not compromised by local concerns to the detriment of the bigger picture. *Market participants* need to apply these definitions as part of their emergency planning.

4.4.1 Definitions Related to Priorities

Critical Power System Loads

Critical power system loads are direct enablers of restoration. Without them, we cannot restore the grid and reliably supply any *consumer* loads. Supplying critical power system loads is the highest priority.

Critical power system loads include AC and DC station service loads necessary to operate power system auxiliaries at control centres, transmission, generating, and step-down transformer stations. In some cases, these loads are also found within *distribution systems*. Examples of the types of auxiliaries supplied as critical power system loads include telecommunications, protective relaying, monitoring and control systems.

Priority Customer Loads

Priority customer loads are important *consumer* loads that need to be restored promptly to mitigate the impact on public health and safety, the environment, or the economy. *Market participants* who are local distribution companies and connected wholesale customers need to identify their priority customer loads.

The urgency for restoring any one *consumer* load may vary depending on circumstances, such as the duration of the interruption, time of day or season, weather conditions, geographical location, or other circumstances related to the nature of the emergency. Local distribution companies need to identify these loads as part of their planning efforts in consultation with consumers, transmitters, local government or emergency management officials. For example, local distribution companies need to design their rotational load shedding (also known as "rotating blackout") procedures with these priorities foremost in mind.

Despite the best of plans, under emergency conditions these priorities could change. *Market participants* need to be flexible and ready to revise priority strategies according to ever-changing circumstances. The following table summarizes the definitions for critical power system and priority customer loads.

Critical Power System and Priority Customer Loads

	Critical Power System	Priority Customer Load[4]
Possible that load may be interrupted without warning?	Yes	Yes
Load is essential for system restoration?	Yes	No
Load is subject to rotating blackouts?	No	No
Examples	Station service at grid facilities Control systems Telecommunications Protective relaying Monitoring	Oil refineries and pipelines Electrically-driven gas pipeline compressors Hospitals <u>without</u> backup generators Water treatment and sewage plants <u>without</u> backup generators

4.4.2 Emergency Load Reduction Guidance for Industrial Consumers

Following a significant system event, there are circumstances when industrial *consumers* may be required to reduce *demand* to maintain system *reliability*. For example, during *emergency operating states*, the *IESO* will take actions that could include implementing rotational or block load shedding to return the system to a reliable state. As a result, industrial *consumers* may be directed to reduce part or all of their load.

When load reductions are required, the *IESO* will either call industrial *consumers* directly or send a recorded broadcast message. For this purpose, industrial *consumers* need to ensure that the *IESO* is kept informed of any changes to their 24/7 emergency operations contacts. Public Appeals and System Status Reports (SSRs) published by the *IESO* alert *market participants* of an *emergency operating state*.

Prior to emergency events, it is important that industrial *consumers* perform risk assessments of their internal processes to segregate essential and non-essential loads so they can implement *IESO*-directed load shedding actions immediately to prevent any delays and to help mitigate impacts to their *facilities* and equipment.

[4] Previously referred to as “Priority 1 Customer”.

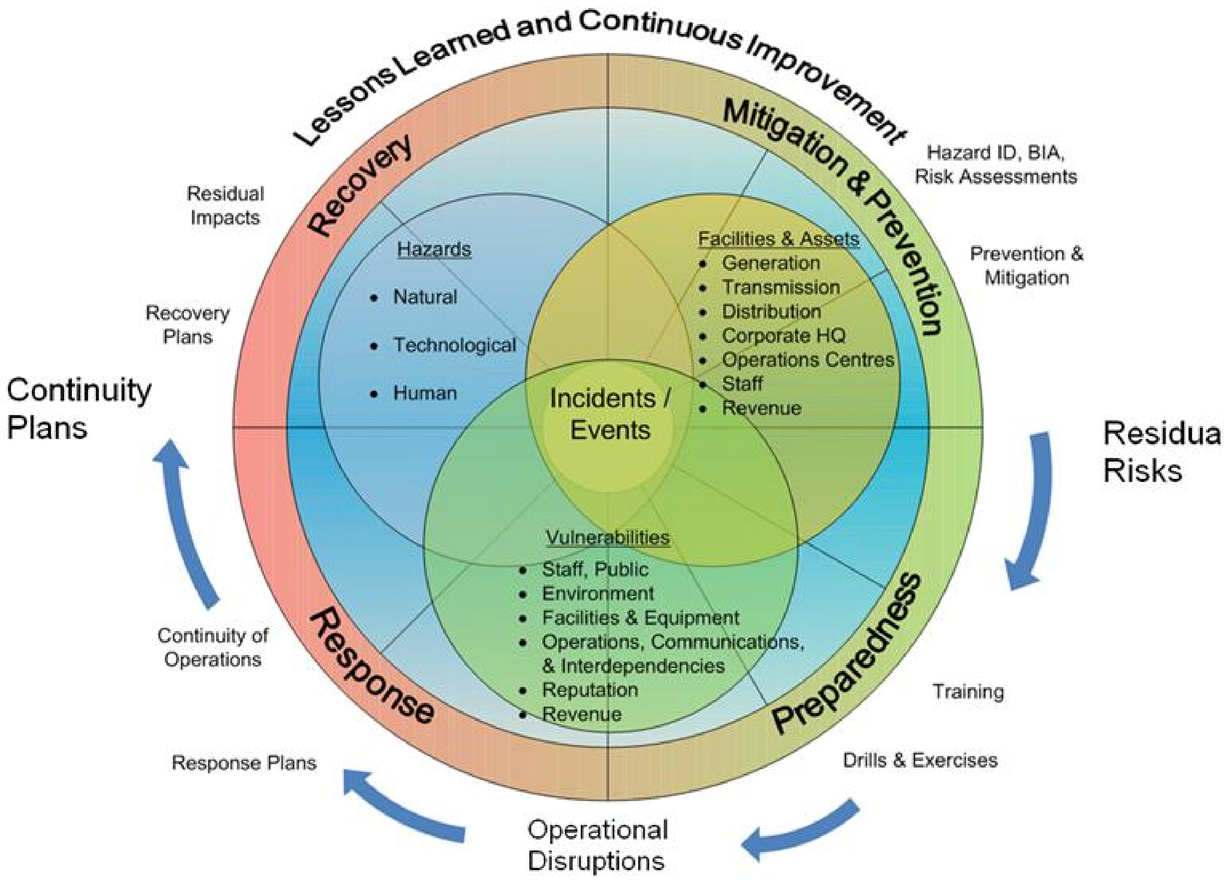
In addition to developing plans to reduce load immediately, industrial *consumers* need to consider how they would reduce load through extended periods of time. Options could include:

- deferring production
- shifting production from peak periods to periods of lower *demand*,
- reducing load to the bare minimum to support safety and environmental issues.

4.5 Emergency Planning Process

The *IESO* and all *market participants* are required to prepare *emergency preparedness plans* to ensure grid reliability. As part of the emergency planning process, the *IESO* and *market participants* should ensure that the risks associated with the hazards listed in Table 4-1 are assessed. If existing *market rules* and *NERC* or other industry standards are not adequate to prevent or mitigate, then the *IESO* through the EPTF may issue additional guidance. *Market participants* should assess the resulting residual risks based on *market rules*, *NERC* or other standards and for residual risks to grid *reliability* that are deemed unacceptable, should develop emergency preparedness, response, and recovery plans. It is recommended that *market participants* similarly address the hazards and risks to their businesses and operations.

This OEEP is aligned with the Canadian Standards Association's Z1600 Emergency Management and Business Continuity standard. As represented in the figure below, this standard is a management system, and provides a broad yet comprehensive framework for all aspects of emergency management – program management, planning, implementation, evaluation, and management review. CSA's Z731 Emergency Preparedness and Response standard provides additional "how-to" detail for some elements of the Z1600 standard.


Lessons Learned and Continuous Improvement
Recovery
Mitigation & Prevention
Preparedness
Response
Hazard ID, BIA, Risk Assessments
Prevention & Mitigation
Residual Impacts
Recovery Plans
Continuity Plans
Residual Risks
Continuity of Operations
Training
Response Plans
Drills & Exercises
Operational Disruptions
Hazards
• Natural
• Technological
• Human
Facilities & Assets
• Generation
• Transmission
• Distribution
• Corporate HQ
• Operations Centres
• Staff
• Revenue
Incidents / Events
Vulnerabilities
• Staff, Public
• Environment
• Facilities & Equipment
• Operations, Communications, & Interdependencies
• Reputation
• Revenue

4.6 Plan Requirements

Market participants are not obliged to use any one standard to develop and maintain their emergency management program, but they do need to address the key planning requirements described in Chapter 5, Section 11 of the Market Rules referenced below. Recognizing that *market participants* have different roles in supporting reliable market and system operations, the plans need to address the questions posed below under the relevant market rules subsection.

4.6.1 Planning (ref. Market Rules, Chapter 5, Section 11.2.4)

- What operating agreements or service arrangements do you have with others to manage the supply or delivery of electricity to or from your facility?
    - **Examples:** Do you have processes in place to quickly reduce load when directed by the *IESO*? Do you have a back-up electricity supply for essential internal loads? Do you have alternate fuel supply arrangements for your backup electricity supply?

- What arrangements do you have in place to respond to an electricity emergency, including coordination with government and local emergency responders such as police, fire and ambulance?
    - **Examples**: Do you have emergency communication protocols in place and phone numbers for your electricity provider(s), government and first responders?

- What mutual aid arrangements are in place with others to support response to an electricity emergency?
    - **Examples**: Do you have any emergency response mutual aid agreements with neighbouring and partnering industries or contracting firms for personnel, equipment or spare parts?

- Do your plans identify critical and priority loads, and how do you mitigate the impact of an electricity emergency on public health and safety?
    - **Examples**: Have you performed a risk-based assessment of your internal loads to segregate essential versus non-essential loads? If you are requested to promptly reduce your load, can it be executed immediately while considering the impacts to your employees, equipment and/or the environment? On a complete loss of grid supply, how will your processes and/or equipment respond? What other public health and safety issues have been considered during such emergencies?

4.6.2 Testing (ref. Market Rules, Chapter 5, Section 11.7)

- How do you test your plans through training, drills, and exercises?
    - **Example**: How are your personnel trained about your emergency preparedness and response plans and how often?

4.6.3 Communication (ref. Market Rules, Chapter 5, Section 11.2.4)

- What is your company's operational contact telephone number, available 24/7?
- What is the telephone number and title of your senior manager who would be contacted in the event of an electricity emergency?

4.6.4 Ontario Power System Restoration Plan (OPSRP)

The OPSRP describes the strategy and planning requirements for restoring the grid following a worst case scenario contingency – a partial or complete system blackout. In addition to providing their *emergency preparedness plan*, *restoration participants* need to prepare a plan describing how they support the OPSRP (ref. Market Manual 7.8 – *Ontario Power System Restoration Plan*). These plans are known as *restoration participant* attachments.

– End of Section –

5. Implementation and the CMST

This section describes how we respond to threats and emergency situations, and distinguishes between **operational** response needed to manage grid *reliability*, and **crisis** response activities coordinated through the Crisis Management Support Team (CMST).

5.1 Prevention and Mitigation

The grid is continuously monitored by well-trained control room operators supported by sophisticated control systems, highly reliable communications, and careful planning and design according to industry standards. Automated alarm systems help experienced operators identify problems on the system so they can take immediate action to contain incidents that would otherwise have a severe impact on the grid. *Market participants* are required to inform the *IESO* of local events or incidents that could affect grid *reliability*. In a worst case scenario, operators are ready to implement the *Ontario Power System Restoration Plan* to restore reliable operation.

A fundamental tenet of effective emergency planning and response is that emergencies are best resolved at the most local level possible. In the context of the *electricity system*, emergencies affecting a single municipality are best addressed by the local distribution company by their own planning and operational resources. If necessary, they activate mutual aid arrangements with their neighbours.

For this reason, the OEEP focuses on situations or events that extend beyond the local level and have the potential for wide-spread, multi-regional, or long-term electricity disruptions. Under these circumstances, the Crisis Management Support Team (CMST) helps coordinate crisis response activities during larger-scale events.

5.2 Resource Management

In addition to the resources needed to conduct normal operations, *emergency preparedness plans* need to consider what additional resources are required to respond effectively to credible scenarios. Aside from managing operational processes, this needs to include staffing and resources to support crisis communications activities.

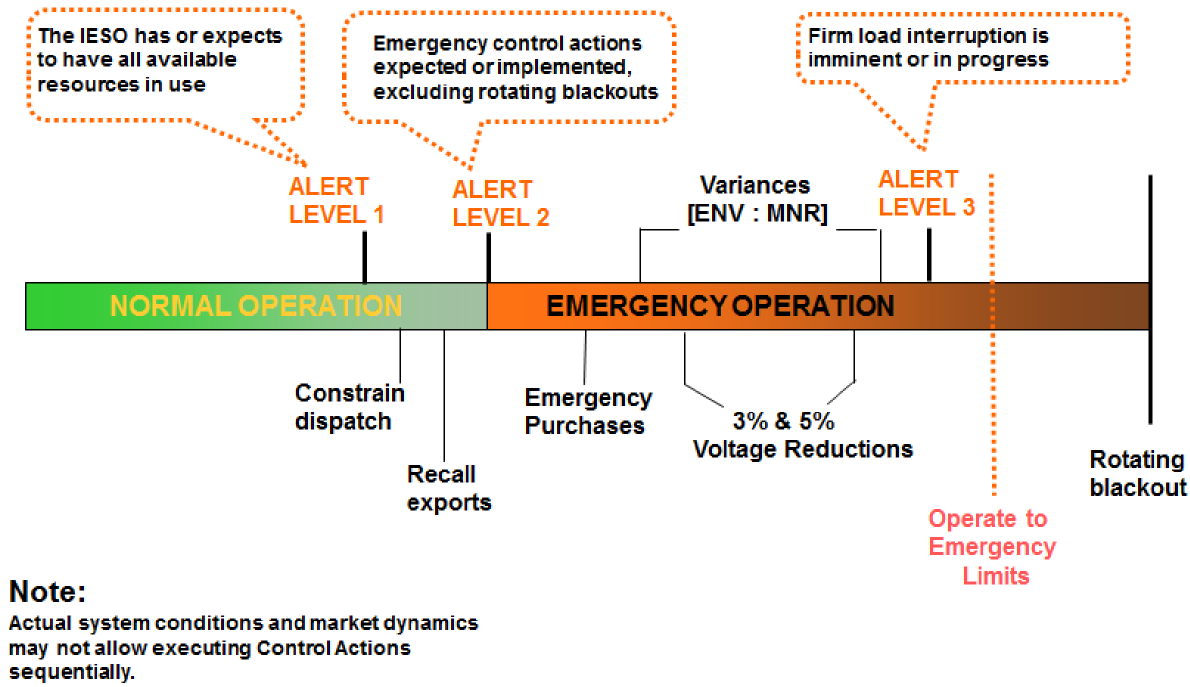
5.3 Mutual Aid and Assistance

It is important that *emergency preparedness plans* consider ways to increase human and material resources when needed. This may include mutual assistance arrangements with others outside the area affected by the emergency. For example, local distribution companies maintain and operate similar infrastructure, equipment and work practices and have a long history of cooperation.

5.4 Emergency Operational Response

As described in section 5.1, emergency response is not a separate activity from normal day-to-day grid operation. It is an integrated part of operational activities that reinforces normal operational roles, accountabilities and processes. For example, control room operators have the authority to decide on and implement emergency control actions, including immediate load shedding if needed, to balance generation supply to meet *consumer* demand. The following diagram illustrates emergency response as a continuum from normal operations.

IESO Emergency Operations Framework



This does not mean to suggest that electricity emergencies are treated as business-as-usual. In addition to the *IESO* and *market participants*' operational efforts to respond to the emergency, we need to activate crisis management resources to maintain situation awareness, support operational response, and inform government, consumers, and other stakeholders. With an Ontario, national, and international perspective foremost in mind, the Crisis Management Support Team fulfills this role.

5.5 The Crisis Management Support Team (CMST)

The purpose of the CMST is to provide a forum for Ontario's electricity *market participants* and stakeholders to share information and co-ordinate crisis management activities leading up to and through a wide spread electricity emergency. The CMST maintains high-level situation awareness, and helps address issues that are not being addressed through operational means. It is important to emphasize that the CMST takes no operational decision-making accountabilities (e.g. directing the operation of the power system) away from participating organizations. **The CMST informs, but does not direct operations or crisis response actions.**

Although the outcomes of CMST conference calls may be considered public, the CMST often needs to share information that may be sensitive in nature and discussions are therefore conducted under non disclosure agreements (NDA). CMST representatives need to respect the source of any information they receive from other CMST representatives and share it only to the extent necessary within their own organizations. For example, CMST Situation Reports may be shared within a CMST representative's own organization but not more broadly.

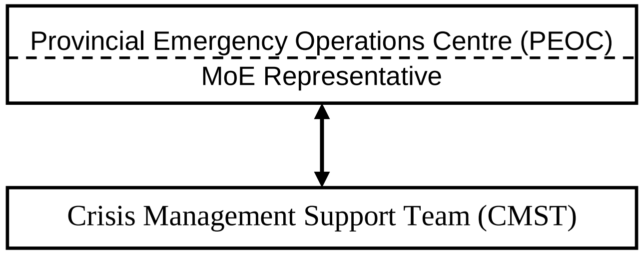
The CMST is chaired by the *IESO* and composed of key representatives from *market participants*, industry associations, and the Ministry of Energy. Participation on the CMST is not intended to be exclusionary but is based on the ability of participants to contribute and their ability to influence positive outcomes. Appendix B provides a current roster of the organizations participating on the CMST.

Guiding Principles

- The CMST does not deal with localized electricity emergencies however CMST calls may be initiated for triage purposes when the impact of an event are not clear;
- CMST coordinates actions and provides input into official communications. CMST is not the communication conduit/medium itself;
- CMST representatives benefit from their participation by exchanging timely information from authoritative and credible sources;
- Industry associations provide an efficient means to engage a significant number of load customers through a single point of contact. Their participation enables them to understand the emergency and, through dialogue with their constituents, take coordinating actions to help mitigate its impact on public health and safety;
- CMST representatives are appointed by their companies, and need to have the authority to share information with the CMST, and influence decision-making on behalf of their organization;
- CMST representatives or their alternates need to sign an NDA and be accessible at any time; and
- Depending on the situation, the CMST Chair may invite organizations not normally represented on the CMST to participate, according to their ability to contribute.

Note. Nuclear operators are required to notify the PEOC of "Reportable" nuclear incidents under the Provincial Nuclear Emergency Response Plan (PNERP). Although this reporting process is outside the CMST process, we expect that CMST representatives of nuclear operators would provide the CMST with information related to any nuclear-specific emergency.

Crisis Management Support Team



5.5.1 Role of the CMST

Gather and share information

- Gather information related to the incident or event;
- Analyze the information to understand potential impacts on public health and safety, the environment, and the economy;
- Maintain overall situation awareness and estimate recovery times;
- Develop situation reports;
- Develop key messages to support consistent official messaging and local communications;
- Distribute information to *market participants* and the Provincial Emergency Operations Centre (PEOC) via the MoE representative, as appropriate.

Identify issues

- Identify unresolved issues, ensure responsible entities are aware, and escalate as necessary.

Develop solutions

- Consider options and alternatives to mitigate the impact on public health and safety, the environment and the economy; and
- Provide analysis, information and advice to the Ministry of Energy.

5.6 Communications and Warning

As described above, the *IESO* continuously monitors the *reliability* of the grid, and receives information from *market participants* regarding events at a local level that could disrupt their operation. While local incidents are managed by the affected participants within the scope of their accountability, the *IESO* directs any actions required of *market participants* to manage overall grid *reliability*.

In parallel with these operational activities, the *IESO* uses its management call chain to quickly identify issues that appear to be significant, and decide what actions need to be taken. As well, early warning of an incident or event may come from any number of other sources – other critical infrastructures (e.g., telecommunications, oil, natural gas), the media, law enforcement or other government agencies.

Regardless of the source of information, the CMST Chair, the *IESO*'s Chief Operating Officer, will consider the circumstances, the guiding principles, consult with CMST representatives, and decide whether to notify or activate the CMST.

5.7 Public Communications

The development of key messages is an important output of the CMST, and CMST representative provide valuable input from their own unique perspectives.

As usual, it is the responsibility of each *market participant* to communicate with their own stakeholders and customers, and CMST representatives are encouraged to use these key messages as part of their own outreach. This will help ensure that the public receives consistent and accurate information from the appropriate entities.

5.8 CMST Activation

CMST members stand ready to notify the *IESO*, or be notified by the *IESO*, of incidents or events that may be of interest to the CMST. The extent of CMST activation depends on the situation, and the following table provides some historical examples.

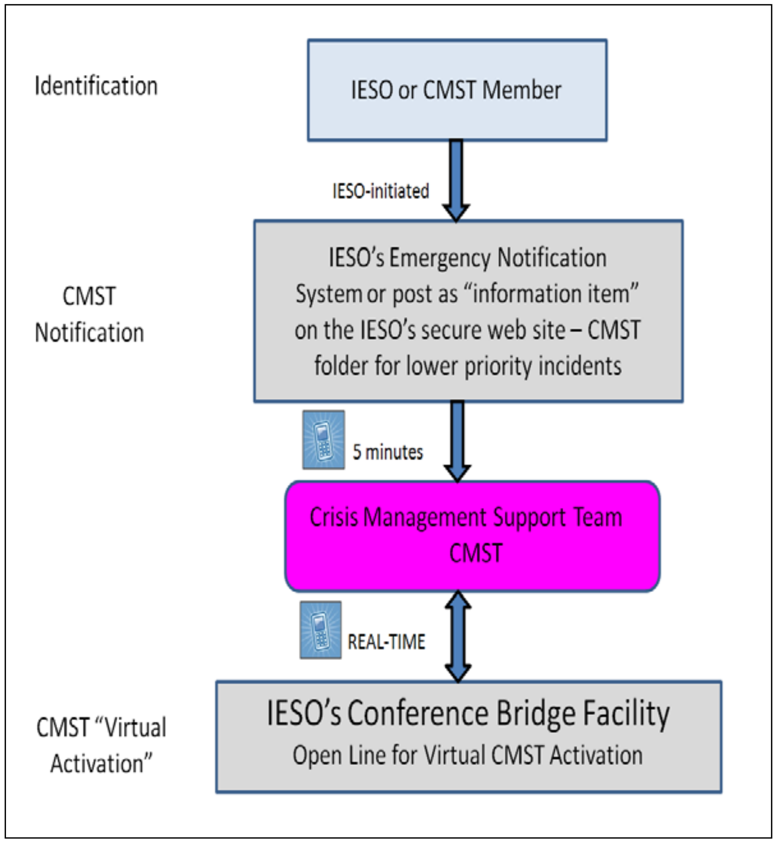
Incident or Event	Extent of CMST Activation
G20 Summit, Toronto (June 21-28, 2010)	CMST calls were initiated daily starting the week prior to and through the G20 event for the purpose of situational updates.
H1N1 influenza outbreak (April 27 – May 12, 2009)	CMST representatives notified as outbreak evolved. Included a CMST conference call on April 27, at least daily updates through May 12, and periodically thereafter.
Preparation for Earth Hour activities (March 28, 2008)	CMST representatives notified day ahead via CMST web posting.
IESO anticipates a period of unprecedented hot and humid weather, and tight electricity supply conditions (August 1-2, 2006)	CMST representative’s notified day ahead, six postings to CMST website as the situation evolved.
Prolonged period of hot, humid weather and very tight electricity supply conditions (Summer 2005)	CMST representatives notified periodically throughout the summer, many postings of CMST Situation Reports to CMST website as the circumstances evolved.
August 2003 Blackout (August 14-22, 2003)	CMST representatives fully activated. Conference bridge opened within 30 minutes, first conference call within an hour of the blackout. CMST operated 24x7 for first two days. Seven conference call meetings on August 14, six on August 15, two or three each day following.

5.8.1 CMST Notification

The *IESO* uses an emergency notification system to alert CMST representatives of incidents or events.

With the support of the EPTF, the *IESO* maintains the CMST roster, and tests the notification system quarterly. The system is web-based and can be activated immediately from any location with web access. Within about five minutes, the system simultaneously calls business, home, and cell numbers, sends an email with a recorded message describing the incident, and tells the CMST representative what to do.

If the incident or event is informational and does not require immediate action from CMST representatives, the *IESO* posts this information to the CMST password-secured web site. A notification email is automatically sent to CMST representatives to advise them of the new posting.



5.8.2 CMST Activation

The CMST conducts its business by conference call. CMST representatives can participate from any location, which allows them to maintain close contact with their own organizations. If the CMST Chair decides to activate the CMST, the *IESO* uses their emergency notification system to inform CMST representatives of the situation, and the time of the conference call. The *IESO* provides a dedicated conference bridge facility for the CMST, ready for immediate use. Typically, the first conference call is arranged within an hour of initial notification.

Conference calls begin with an introduction from the Chair and an update from the *IESO*. CMST representatives provide additional information from their own sources, and have the opportunity to ask questions and discuss issues. The CMST focuses on issues at a strategic level and does not get into operational details. The *IESO* prepares a situation report to record the results of the conference call and posts it on the CMST web site.

5.9 Facilities

The *IESO* provides the emergency notification system, a password-secured web site, and a high-availability conference bridge.

CMST representatives provide their own means to participate on conference calls and connect to the web.

5.10 Training

CMST representatives have a number of training opportunities to become familiar with their roles. The *IESO* provides an orientation for newly-appointed representatives that includes an overview of the OEEP, how to access the secure web site, and references to procedures. Periodically, a CMST workshop is held to provide CMST representatives with an opportunity to meet each other face-to-face, review CMST procedures, and walk-through how the CMST responds to an emergency scenario. The CMST exercises its role as part of the large-scale integrated exercises that involve the *IESO*, *market participants*, and government stakeholders.

5.11 Operational Continuity

While the CMST does not have an operational role, their actions support operational continuity by addressing crisis communications and consequence management needs.

– End of Section –

6. Exercises, Evaluations and Corrective Actions

While the *IESO* and *market participants* are responsible for training their own staff, all agree there is great value in learning together how we coordinate to respond to real events. Every year, the *IESO* and *market participants* plan and execute training sessions, workshops, and exercises. The *IESO*'s Emergency Drills and Exercises Guide provides advice on how to plan and conduct drills and exercises. It also provides a framework for evaluating lessons-learned, and deciding corrective actions.

6.1 Exercises

The *IESO* and *market participants* need to train staff and exercise their plans and procedures. Exercises are a prominent part of the EPTF Work Plan. Since 2001, large-scale integrated exercises have helped the *IESO* and *market participants* test their own internal plans and ensure they are well-coordinated with others. As well, workshops are held periodically across Ontario to reinforce reliable operations and simulate response to a local scenario in detail.

6.2 Evaluations

The *IESO* and *market participants* review the results of training and exercises to assess their effectiveness, take corrective action, and plan to improve them in future. Feedback from individuals helps determine if the overall objectives were achieved, and if the presentation format could be improved. Every year, the *IESO* summarizes this feedback and determines with the EPTF ways to continuously improve the value and effectiveness of these workshops and exercises.

For large-scale exercises, the *IESO* asks participants to identify their findings and lessons-learned. In consultation with the EPTF, these findings are documented in an exercise evaluation report.

6.3 Corrective Actions

Workshops and exercises are of little value if they do not identify specific and actionable areas for improvement. While it is important not to gloss over errors or deficiencies that occur during an exercise, care should be taken to acknowledge them openly in the spirit of continuous improvement. It is also important to rank them so that resources are applied to the right priorities. To evaluate the results of large-scale exercises, the *IESO* uses the following ranking criteria.

Rank	Description
Observation	Finding has little direct impact on emergency response or restoration, but should be considered as an improvement to emergency response processes.
Gap	Finding has some measurable impact on timeliness of restoration or effectiveness of emergency response.
Significant Gap	Finding has a significant impact on timeliness of restoration or effectiveness of emergency response, with a significant impact on public health and safety.

As part of its work planning activities, the EPTF periodically reviews the status of actions needed to address exercise findings, and ensures that sufficient progress has been made to support success at future exercises.

– End of Section –

7. Management Review

7.1 OEEP Maintenance

The *IESO* is responsible for maintaining the OEEP, filing any revisions with the *Minister*, and making the OEEP publicly available on the *IESO* web site.

7.2 Annual Review

The *IESO* reviews the OEEP annually, and consults with the EPTF regarding any changes.

Market participants are encouraged to conduct internal reviews, peer reviews, self-audits or external audits to assess their own plans and state of readiness. These independent assessments benefit *market participants* and the industry.

7.3 Independent Audit

If directed by the *Minister*, the *IESO* will arrange for an audit of the OEEP by the *IESO*'s internal auditors or a peer review team composed of diverse industry or emergency preparedness experts.

- End of Section -

Appendix A: EPTF Roster

Emergency Preparedness Task Force (EPTF) Roster	
EPTF Chair	Independent Electricity System Operator (*IESO*)
Generators	Bruce Power Ontario Power Generation Brookfield Renewable Power
Transmitters	Hydro One Great Lakes Power Transmission
Local distribution companies	Toronto Hydro Hydro One Hydro Ottawa PowerStream
Industry associations	Association of Major Power Consumers of Ontario (AMPCO) Electricity Distributors Association (EDA) Association of Power Producers of Ontario (APPrO)
Government	Ministry of Energy (MoE) Emergency Management Ontario (EMO) Public Safety Canada (PS)
Other Industries	Enbridge Gas Distribution

- End of Section -

Appendix B: CMST Roster and Responsibilities

CMST Roster	
CMST Chair	Independent Electricity System Operator (*IESO*)
Generators	Bruce Power Ontario Power Generation Brookfield Renewable Power
Transmitters	Hydro One Great Lakes Power Transmission
Local distributing companies	Toronto Hydro Hydro One Hydro Ottawa
Industry Associations	Association of Major Power Consumers of Ontario Electricity Distributors Association Association of Power Producers of Ontario Building Owners and Managers Association
Other Industries	Enbridge Gas Distribution Inc Union Gas Ltd.
Government	Ministry of Energy

CMST Representative Responsibilities

Each CMST representative has specific responsibilities and assigned tasks when the CMST is activated.

Independent Electricity System Operator (*IESO*)

The *IESO*'s Chief Operating Officer chairs the CMST, decides when to activate and stand-down, and provides the resources needed to activate and support the operation of the CMST. As well, the *IESO* is a primary source of information such as:

- The status of Ontario's *electricity system* and market operation
- Affected areas
- Estimates of time to restore
- Status of interconnected operation with jurisdictions outside of Ontario
- Restoration priorities
- Prognosis for future operation

- Forecasts of weather, *consumer* demand and system adequacy

Ministry of Energy (MoE)

The MoE representative ensures that the CMST, PEOC and MoE communicate effectively during an emergency. The Ministry of Energy representative:

- Ensures that MoE is kept informed of the status of the emergency, including actions being taken by the *IESO* and *market participants* to ensure that power is restored as quickly as possible
- Ensures that issues related to public policy are referred to the MoE
- Ensures the PEOC's information needs regarding the electricity sector are met
- Identifies *IESO* or *market participants*' needs for provincial or federal government support
- Requests additional support from CMST, when necessary, to support the MoE representative at the PEOC
- Ensures the CMST's key public messages are shared with the PEOC Information Group so that CMST and government public messages are consistent

The PEOC is active 7/24 so that it can respond immediately to emergencies. The PEOC is a multi-agency facility, and includes an MoE representative. It is designated by the province to coordinate provincial emergency operations and to provide support to affected communities. Representatives of ministries, federal agencies and other organizations provide status reports and coordinate response activities.

Emergency Information Centre (EIC)

The EIC presents coordinated emergency information from all involved levels of government to the media and the general public.

In a provincial emergency, local, provincial and, in some cases, federal emergency information resources may be combined to create an Emergency Information Centre (EIC). Depending on the nature of the emergency event, this could be located at or near the PEOC, or could be deployed close to the area affected by the emergency. For nuclear, the Provincial Nuclear Plan defines these areas.

Ontario Power Generation (OPG)

The OPG representative is responsible for:

- Reporting to the CMST
- Notifying the OPG Director Emergency Operations – CMCC at the OPG Crisis Management and Communications Centre (CMCC) of CMST activation
- Requesting activation of the OPG Crisis Management and Communications Centre, if necessary
- Establishing and maintaining contact with the OPG Director Emergency Operations – CMCC
- Providing status reports on OPG resources to the CMST
- Providing feedback to the OPG Director Emergency Operations – CMCC on the status of the emergency situation and CMST planned actions

Bruce Power

The Bruce Power representative is responsible for:

- Reporting to the CMST
- Notifying Bruce Power's internal emergency response organization of CMST activation
- Requesting activation of the internal emergency response organization, if necessary
- Establishing and maintaining contact with the Bruce Power response efforts
- Providing status report on Bruce Power resources to the CMST
- Providing feedback to the Bruce Power emergency response organization on the status of the emergency situation and planned CMST actions

Electricity Distributors Association (EDA)

The primary responsibility of the EDA representative is to provide a link between the CMST and Electricity Distributors Association (EDA) member electric utilities in the affected area. The *market rules* require all *market participants* to prepare and implement their own *emergency preparedness plans* independently or with support through their own mutual aid arrangements. It is expected that EDA member utilities will coordinate directly with local community emergency response personnel. Similarly, it is expected that community emergency response personnel will coordinate directly with the PEOC to mitigate impacts on public health and safety.

The Electricity Distributor representative, through liaison with EDA members, either directly or via district field representatives:

- Arranges for surveys of municipal utilities and provides an estimate of damage and geographical identification of the affected areas
- Assists in identifying high priority areas in need of assistance and provides details regarding the nature of assistance required
- Identifies assistance that is available from municipal electric utilities to assist other *market participants* in an emergency
- Informs the EDA regarding the status of the emergency and CMST actions

Hydro One

The Hydro One representative at the CMST helps other *market participants* to coordinate emergency response and recovery actions across the province, and to formulate recovery strategies for the bulk *electricity system*. In this capacity, the Hydro One representative reports on the status of the grid, load and generator connections, and the estimated time required to restore service to affected areas. The Hydro One representative also:

- Conveys Hydro One requests to the CMST for additional resources in support of Hydro One restoration activities
- Reports on the status of restoration activities on their distribution and retail operations
- Reports on the availability of Hydro One resources for deployment in support of other *market participants*

Great Lakes Power Transmission

The Great Lakes Power Transmission representative at the CMST helps other *market participants* to coordinate emergency response and recovery actions across the province, and to formulate recovery strategies for the bulk *electricity system*. In this capacity, the Great Lakes Power Transmission representative reports on the status of the grid, load and generator connections, and the estimated time required to restore service to affected areas. The Great Lakes Power Transmission representative also:

- Conveys Great Lakes Power Transmission requests to the CMST for additional resources in support of Great Lakes Power Transmission restoration activities
- Reports on the status of restoration activities on their *distribution* and retail operations
- Reports on the availability of Great Lakes Power Transmission resources for deployment in support of other *market participants*

Brookfield Renewable Power

- Reporting to the CMST
- Providing status report on Brookfield Renewable Power resources to the CMST
- Providing feedback to the Brookfield Renewable Power emergency response organization on the status of the emergency situation and planned CMST actions

Toronto Hydro-Electric System (THES)

The THES representative at the CMST:

- Provides information and cooperation to the CMST to assist in developing a long-term electricity sector recovery strategy and helps with other CMST responsibilities
- Ensures that THES resources, facilities, infrastructure and personnel are adequate to comply with emergency response and system restoration requirements
- Provides reports to the THES Emergency Operations Center Coordinator and provides the THES Restoration Planning Coordinator with reports regarding the status of the system and CMST actions
- Requests a declaration of emergency for the THES service area, if necessary
- Informs the CMST of the availability of THES resources to assist other *market participants* in restoring services in the affected areas

Hydro Ottawa

The Hydro Ottawa representative at the CMST:

- Provides information and cooperation to the CMST to assist in developing a long-term electricity sector recovery strategy and help with other CMST responsibilities
- Ensures that Hydro Ottawa resources, facilities, infrastructure and personnel are adequate to comply with emergency response and system restoration requirements
- Provides reports to the Hydro Ottawa Emergency Operations Center Coordinator and provides the Hydro Ottawa Restoration Planning Coordinator with reports regarding the status of the system and CMST actions
- Requests a declaration of emergency for the Hydro Ottawa service area, if necessary
- Informs the CMST of the availability of Hydro Ottawa resources to assist other *market participants* in restoring services in the affected areas

Association of Major Power Consumers of Ontario (AMPCO)

The primary responsibility of the AMPCO representative is to provide a communications link between the CMST and AMPCO member companies in the affected area. We recognize that an electricity emergency would have a significant impact on industrial *consumers*, and AMPCO participation on the CMST provides a valuable two-way flow of information regarding the scope and extent of any electricity disruption as well as any mitigating measures being implemented.

As required by the *market rules*, all AMPCO members who are *market participants* are required to prepare and implement their own *emergency preparedness plans*, including coordination with local community emergency response personnel. It is recognized through this arrangement that AMPCO does not have operational control or authority over its member companies. The AMPCO representative, through liaison with AMPCO members:

- Participates in CMST discussions and provides input to the CMST from the perspective of industrial consumers
- Informs AMPCO members regarding the status of the emergency and CMST actions and decisions
- Respects the confidentiality of information shared at the CMST by limiting information shared with AMPCO members on a need-to-know basis
- Identifies issues of critical interest to industrial consumers and proposes suitable solutions (e.g., sustained conservation or curtailment options)
- Assists in developing key public messages

Building Owners and Managers Association (BOMA)

The primary responsibility of the BOMA representative is to provide a communications link between the CMST and BOMA member companies in the affected area.

The BOMA representative at the CMST:

- Participates in CMST discussions and provides input to the CMST from the perspective of BOMA consumers
- Informs BOMA members regarding the status of the emergency and CMST actions and decisions
- Respects the confidentiality of information shared at the CMST by limiting information shared with BOMA members on a need-to-know basis
- Identifies issues of critical interest to commercial *consumers* and proposes suitable solutions (e.g., sustained conservation or curtailment options)
- Assists in developing key public messages

Natural Gas Companies

The Natural Gas Company (*) CMST representative during an emergency event:

- Acts as the primary Liaison between the CMST and the Gas companies
- Provides information and status updates to the CMST regarding impacts to the gas systems and emergency response or recovery activities that may affect other CMST members organizations
- Requests information and cooperation from the CMST and its individual members as may be necessary to sustain or recover gas systems
- Informs the CMST of the availability and readiness of gas systems to assist other market participants in restoring electrical services in the affected areas

(*) Natural Gas Company representatives: Union Gas and Enbridge

– End of Document –

Texas

ERCOT Energy Emergency Alert Communications

Emergency Levels	Operating Reserves	Grid Operators' Actions	Automated Emergency Notifications	Follow-up Communications from External Affairs	Media/Public Notifications
Normal Conditions	Reserves > 3,000 MW	Normal operations			
Control Room Advisory	Reserves < 3,000 MW	Issue "Advisory" to utilities -- informational only -- no additional authority for operators' actions.	Public Utility Commission (PUC) and NERC regional entity (TRE) notified via grid report daily emails		
Control Room Watch	Reserves < 2,500 MW	Use quick-start capacity and non-spinning reserves (available within 30 minutes).	Automated Emergency Notification System phone call and email to PUC, the independent market monitor (IMM), TRE, and FERC	If potential emergency situation, additional information sent to the GridEmergency email list (SOC, PUC, OPC, RRC, TCEQ, Board, Govmt/Lege, IMM, TRE, FERC, and Market Participants' media contacts/PIOs)	
Energy Emergency Level 1 POWER WATCH - Conservation Needed (appeal optional if situation short-lived)	Reserves < 2,300 MW	Use capacity available from other grids (via asynchronous connections; 500 MW on average) and commit all available units.	Above plus State Operations Center (notifies city, county officials & law enforcement), Office of Public Utility Counsel, govmt/lege staff and ERCOT Board	If needed, notify GridEmergency list with additional information	News release, if appropriate; Emergency Alerts list,** Twitter and Facebook
Energy Emergency Level 2 POWER WARNING - Conservation Critical	Reserves < 1,750 MW	Deploy demand response resources: Load Resources under contract (1,000 MW on average) and/or Emergency Responsive Service* (400-500 MW on average), in either order. Begin block load transfers of load to other grids if appropriate.	Above plus major news services and media contacts for utilities	Same as above	News release, if appropriate; Emergency Alerts,Twitter and Facebook
Energy Emergency Level 3 POWER EMERGENCY - Rotating Outages	Reserves continuing to trend downward or frequency at or below 59.8 Hz	Instruct transmission operators to implement rotating outages. Areas affected are at the discretion of the utilities.	Same as above	Same as above	News release; Emergency Alerts list, Twitter and Facebook

*Emergency Interruptible Load Service becomes Emergency Response Service on June 1, 2012.

** Sign-up for Emergency Alerts and News Bulletins list at http://lists.ercot.com

Report on the Capacity, Demand, and Reserves in the ERCOT Region

May 2013

Contents

Disclaimer

CDR WORKING PAPER

FOR PLANNING PURPOSES ONLY

This ERCOT Working Paper has been prepared for specific ERCOT and market participant purposes and has been developed from data provided by ERCOT market participants. The data may contain errors or become obsolete and thereby affect the conclusions and opinions of the Working Paper. ERCOT MAKES NO WARRANTY, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE, AND DISCLAIMS ANY AND ALL LIABILITY WITH RESPECT TO THE ACCURACY OF SAME OR THE FITNESS OR APPROPRIATENESS OF SAME FOR ANY PARTICULAR USE. THIS ERCOT WORKING PAPER IS SUPPLIED WITH ALL FAULTS. The specific suitability for any use of the Working Paper and its accuracy should be confirmed by each ERCOT market participant that contributed data for this Working Paper.

This Working Paper is based on data submitted by ERCOT market participants as part of their Annual Load Data Request (ALDR) and their resource asset registration and on data in the EIA-411. As such, this data is updated on an ongoing basis, which means that this report can be rendered obsolete without notice.

Definitions

Available Mothballed Generation
The probability that a mothballed unit will return to service, as provided by its owner, multiplied by the capacity of the unit. Return probabilities are considered protected information under the ERCOT Protocols and therefore are not included in this report.

Effective Load-Carrying Capability (ELCC) of Wind Generation
The amount of wind generation that the Generation Adequacy Task Force (GATF) has recommended to be included in the CDR. The value is 8.7% of the nameplate capacity listed in the Unit Capacities tables, both installed capacity and planned capacity.

Forecast Zone
Forecast Zones have the same boundaries as the 2003 ERCOT Congestion Management Zones. Each Resource will be mapped to a Forecast Zone during the registration process.

LRs (Load Resources)
Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services to the ERCOT System, as described in the ERCOT Protocols, Section 6, Ancillary Services. These Resources may provide the following Ancillary Services: Responsive Reserve Service, Non-Spinning Reserve Service, Replacement Reserve Service, and Regulation Service. The Resources must be registered and qualified by ERCOT and will be scheduled by a Qualified Scheduling Entity

Mothballed Capacity
The difference in the available mothballed generation (see definition above) and the total mothballed capacity.

Mothballed Unit
A generation resource for which a generation entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute an RMR agreement, and for which the generation entity has not announced retirement of the generation resource.

Net Dependable Capability
Maximum sustainable capability of a generation resource as demonstrated by performance testing.

Non-Synchronous Tie
Any non-synchronous transmission interconnection between ERCOT and non-ERCOT electric power systems

Other Potential Resources
Capacity resources that include one of the following:

- Remaining "mothballed" capacity not included as resources in the reserve margin calculation
- Remaining DC tie capacity not included as resources in the reserve margin calculation, and
- New generating units that have initiated full transmission interconnection studies through the ERCOT generation interconnection process (Note that new wind units would be included based on the appropriate discounted capacity value applied to existing wind generating units.)

Planned Units in Full Interconnection Study Phase
To connect new generation to the ERCOT grid, a generation developer must go through a set procedure. The first step is a high-level screening study to determine the effects of adding the new generation on the transmission system. The second step is the full interconnection study. These are detailed studies done by the transmission owners to determine the effects of the addition of new generation on the transmission system.

Private Networks
An electric network connected to the ERCOT transmission grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation).

Reliability Must-Run (RMR) Unit
A generation resource unit operated under the terms of an agreement with ERCOT that would not otherwise be operated except that they are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria.

Signed IA (Interconnection Agreement)
An agreement that sets forth requirements for physical connection between an eligible transmission service customer and a transmission or distribution service provider

Switchable Unit
A generation resource that can be connected to either the ERCOT transmission grid or a grid outside the ERCOT Region.

Changes from 2012 CDR (December Update)

1 Retirement of two Leon Creek units (LCP3G3 & LCP4G4) that were previously mothballed

2 Whitney Dam 1 entered into mothball status

3 All SR Bertron units were returned to service from mothball status

4 The commercial operation date for the Panda Sherman and Temple I projects was moved up from mid to early summer 2014

5 The following projects have finalized the necessary agreements and permits to be added to CDR:

Project Name	Year In Service	County	Fuel	MW Capacity
WA Parish Addition	2014	Fort Bend	Gas	90
Deepwater Energy Storage	2014	Harris	Storage	40
OCI Alamo 1	2014	Bexar	Solar	50
Deer Park Energy Center	2014	Harris	Gas	195
Channel Energy Center 138/345kV CT	2014	Harris	Gas	190
Antelope Station	2016	Hale	Gas	364
Spinning Spur Wind Two	2014	Oldham	Wind	161
Mariah Wind 1	2014	Parmer	Wind	200
Panhandle Wind	2014	Carson	Wind	322
Miami Wind 1 Project	2014	Gray	Wind	401
Mariah Wind 2	2015	Parmer	Wind	200
Longhorn Energy Center	2015	Briscoe	Wind	361
South Clay Windfarm	2015	Clay	Wind	200
Mariah Wind 3	2015	Parmer	Wind	200

Executive Summary

ERCOT has developed this report using data provided by resource owners and by transmission service providers. Although ERCOT works to ensure that the data provided are as accurate and current as possible, we cannot independently verify all of the information provided to us. The methodology for developing this report is defined in Chapter 3 of the ERCOT Protocols (see: http://www.ercot.com/content/mktrules/nprotocols/current/03-040213_Nodal.doc). Information available to ERCOT as of April 19, 2012, is included in this report.

Current information indicates that the planning reserve margin in the ERCOT region will be above the target reserve margin of 13.75% for the 2014 peak season but will then fall below the target level for the remainder of the reporting period. The planning reserve margin for the peak season of 2014 is forecasted to be 13.8%. This number is higher than the 2014 forecast provided in the December 2012 CDR because ERCOT was recently notified by the developer of the Panda Temple I and Panda Sherman combined-cycle plants that these facilities will start commercial operations by early June 2014; as a result, these units are now included in the list of units available for peak season 2014. There is one other combined-cycle facility, the Ferguson unit, currently under construction. This unit is scheduled to begin commercial operations during the summer of 2014. If this unit is also available at the time of system peak in 2014, the effective planning reserve margin will be 14.6%.

The load forecast included in this assessment is based on economic data contained in Moody's latest "Low Economic Growth" forecast for the ERCOT region. For more information regarding this forecast, please see: http://www.ercot.com/content/meetings/gatf/keydocs/2012/1203/2012_Long-Term_Load_Forecast_Update_GATF_-_December_2012.ppt.

The expected amount of participation in the Emergency Response Service noted in the Summer Summary table does not include the resources participating in the 30-Minute Emergency Response Service Pilot Project (approximately 80 MW) as this service has not been codified in market protocols at this time.

CPS Energy has publicly announced its plans to deactivate the two coal-fired J. T. Deely units (a combined 845 MW) by the end of 2018. Although ERCOT has not been formally notified of this change in unit status (as required by market protocols at least 90 days prior to the proposed idling of a registered resource), based on the information made available by CPS Energy, these units are assumed to be taken off-line in this assessment in the year noted above.

2013 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary

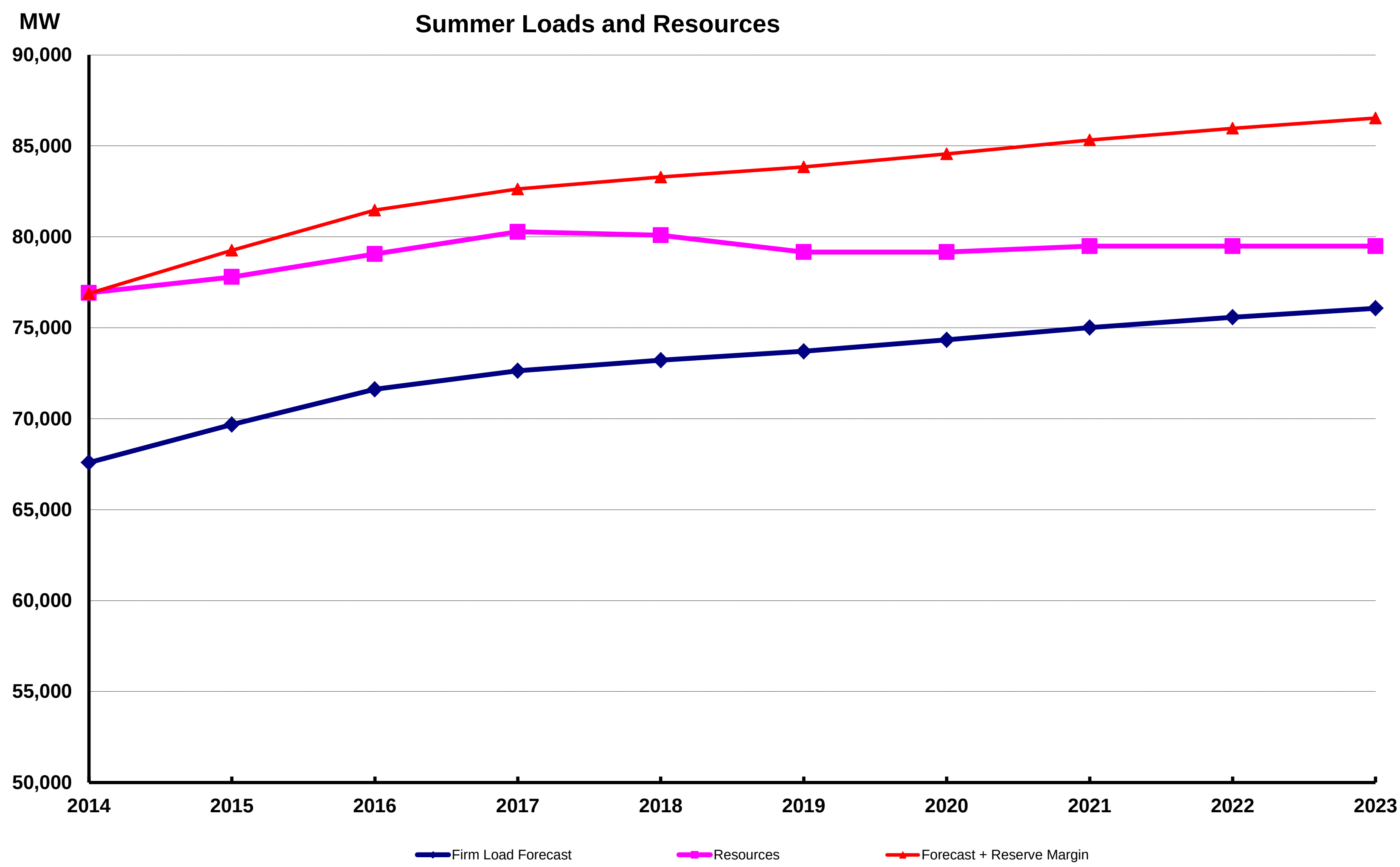
Load Forecast:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total Summer Peak Demand, MW	69,807	72,071	74,191	75,409	76,186	76,882	77,608	78,380	79,055	79,651
less LRS Serving as Responsive Reserve, MW	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222
less LRS Serving as Non-Spinning Reserve, MW	0	0	0	0	0	0	0	0	0	0
less Emergency Response Service	475	523	575	632	696	765	842	926	1019	1121
less Energy Efficiency Programs (per Utilities Code Section 39.905 (b-4))	518	648	781	917	1054	1193	1210	1225	1238	1238
Firm Load Forecast, MW	**67,592**	**69,679**	**71,613**	**72,637**	**73,214**	**73,702**	**74,334**	**75,007**	**75,576**	**76,070**

Resources:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Installed Capacity, MW	64,998	64,998	64,998	64,998	64,998	64,998	64,998	64,998	64,998	64,998
Capacity from Private Networks, MW	4,331	4,331	4,331	4,331	4,331	4,331	4,331	4,331	4,331	4,331
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	920	920	920	920	920	920	920	920	920	920
RMR Units to be under Contract, MW	0	0	0	0	0	0	0	0	0	0
Operational Generation, MW	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**	**70,248**
50% of Non-Synchronous Ties, MW	628	628	628	628	628	628	628	628	628	628
Switchable Units, MW	2,977	2,977	2,977	2,977	2,977	2,977	2,977	2,977	2,977	2,977
Available Mothballed Generation, MW	618	722	590	430	246	167	167	167	167	167
Planned Units (not wind) with Signed IA and Air Permit, MW	2,927	3,497	4,881	6,261	6,261	6,261	6,261	6,261	6,261	6,261
ELCC of Planned Wind Units with Signed IA, MW	187	389	399	399	399	399	399	399	399	399
Total Resources, MW	**77,586**	**78,462**	**79,724**	**80,944**	**80,760**	**80,681**	**80,681**	**80,681**	**80,681**	**80,681**

less Switchable Units Unavailable to ERCOT, MW	-317	-317	-317	-317	-317	-317	-317	0	0	0
less Retiring Units, MW	-354	-354	-354	-354	-354	-1,199	-1,199	-1,199	-1,199	-1,199
Resources, MW	**76,915**	**77,791**	**79,053**	**80,273**	**80,089**	**79,165**	**79,165**	**79,482**	**79,482**	**79,482**
Reserve Margin	**13.8%**	**11.6%**	**10.4%**	**10.5%**	**9.4%**	**7.4%**	**6.5%**	**6.0%**	**5.2%**	**4.5%**
(Resources - Firm Load Forecast)/Firm Load Forecast										

2013 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary



Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Alvin	AV_DG1	Galveston	Biomass	Houston	2002	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Austin Landfill Gas	DG_SPRIN_4UNITS	Travis	Biomass	South	2007	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Covel Gardens Power Station	DG_MEDIN_1UNIT	Bexar	Biomass	South	2005	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
DFW Gas Recovery	DG_BIO2_4UNITS	Denton	Biomass	North	2009	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
DG_Bioenergy Partners	DG_BIOE_2UNITS	Denton	Biomass	North	1988	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Farmer's Branch Landfill	DG_HBR_2UNITS	Denton	Biomass	North	2011	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
FW Region Gen Facility	DG_RDLML_1UNIT	Tarrant	Biomass	North	2006	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Humble	HB_DG1	Harris	Biomass	Houston	2002	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Liberty	LB_DG1	Harris	Biomass	Houston	2002	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Lufkin Biomass	LFBIO_UNIT1	Angelina	Biomass	North	2011	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
McKinney Landfill	DG_MKNSW_2UNITS	Collin	Biomass	North	2011	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Mesquite Creek Energy	DG_FREIH_2UNITS	Comal	Biomass	South	2010	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Nacogdoches Power	NACPW_UNIT1	Nacogdoches	Biomass	North	2012	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0
Skyline Landfill Energy	DG_FERIS_4UNITS	Dallas	Biomass	North	2007	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Trinity Bay	TRN_DG1	Chambers	Biomass	Houston	2002	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Trinity Oaks LFG	DG_KLBRG_1UNIT	Dallas	Biomass	North	2009	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Walzem Road	DG_WALZE_4UNITS	Bexar	Biomass	South	2002	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Westside	DG_WSTHL_3UNITS	Parker	Biomass	North	2010	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Big Brown 1	BBSES_UNIT1	Freestone	Coal	North	1971	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
Big Brown 2	BBSES_UNIT2	Freestone	Coal	North	1972	595.0	595.0	595.0	595.0	595.0	595.0	595.0	595.0	595.0	595.0
Coleto Creek	COLETO_COLETOG1	Goliad	Coal	South	1980	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0
Fayette Power Project 1	FPPYD1_FPP_G1	Fayette	Coal	South	1979	604.0	604.0	604.0	604.0	604.0	604.0	604.0	604.0	604.0	604.0
Fayette Power Project 2	FPPYD1_FPP_G2	Fayette	Coal	South	1980	599.0	599.0	599.0	599.0	599.0	599.0	599.0	599.0	599.0	599.0
Fayette Power Project 3	FPPYD2_FPP_G3	Fayette	Coal	South	1988	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0
Gibbons Creek 1	GIBCRK_GIB_CRG1	Grimes	Coal	North	1982	470.0	470.0	470.0	470.0	470.0	470.0	470.0	470.0	470.0	470.0
J K Spruce 1	CALAVERS_JKS1	Bexar	Coal	South	1992	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
J K Spruce 2	CALAVERS_JKS2	Bexar	Coal	South	2010	775.0	775.0	775.0	775.0	775.0	775.0	775.0	775.0	775.0	775.0
J T Deely 1	CALAVERS_JTD1	Bexar	Coal	South	1977	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0
J T Deely 2	CALAVERS_JTD2	Bexar	Coal	South	1978	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
Limestone 1	LEG_LEG_G1	Limestone	Coal	North	1985	831.0	831.0	831.0	831.0	831.0	831.0	831.0	831.0	831.0	831.0
Limestone 2	LEG_LEG_G2	Limestone	Coal	North	1986	858.0	858.0	858.0	858.0	858.0	858.0	858.0	858.0	858.0	858.0
Martin Lake 1	MLSES_UNIT1	Rusk	Coal	North	1977	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0
Martin Lake 2	MLSES_UNIT2	Rusk	Coal	North	1978	805.0	805.0	805.0	805.0	805.0	805.0	805.0	805.0	805.0	805.0
Martin Lake 3	MLSES_UNIT3	Rusk	Coal	North	1979	805.0	805.0	805.0	805.0	805.0	805.0	805.0	805.0	805.0	805.0
Monticello 1	MNSES_UNIT1	Titus	Coal	North	1974	535.0	535.0	535.0	535.0	535.0	535.0	535.0	535.0	535.0	535.0
Monticello 2	MNSES_UNIT2	Titus	Coal	North	1975	535.0	535.0	535.0	535.0	535.0	535.0	535.0	535.0	535.0	535.0
Monticello 3	MNSES_UNIT3	Titus	Coal	North	1978	795.0	795.0	795.0	795.0	795.0	795.0	795.0	795.0	795.0	795.0
Oak Grove SES Unit 1	OGSES_UNIT1A	Robertson	Coal	North	2011	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0
Oak Grove SES Unit 2	OGSES_UNIT2	Robertson	Coal	North	2011	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0
Oklaunion 1	OKLA_OKLA_G1	Wilbarger	Coal	West	1986	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0
San Miguel 1	SANMIGL_SANMIGG1	Atascosa	Coal	South	1982	391.0	391.0	391.0	391.0	391.0	391.0	391.0	391.0	391.0	391.0
Sandow 5	SD5SES_UNIT5	Milam	Coal	South	2010	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0
Twin Oaks 1	TNP_ONE_TNP_O_1	Robertson	Coal	North	1990	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0
Twin Oaks 2	TNP_ONE_TNP_O_2	Robertson	Coal	North	1991	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0
W A Parish 5	WAP_WAP_G5	Ft. Bend	Coal	Houston	1977	659.0	659.0	659.0	659.0	659.0	659.0	659.0	659.0	659.0	659.0
W A Parish 6	WAP_WAP_G6	Ft. Bend	Coal	Houston	1978	658.0	658.0	658.0	658.0	658.0	658.0	658.0	658.0	658.0	658.0
W A Parish 7	WAP_WAP_G7	Ft. Bend	Coal	Houston	1980	577.0	577.0	577.0	577.0	577.0	577.0	577.0	577.0	577.0	577.0
W A Parish 8	WAP_WAP_G8	Ft. Bend	Coal	Houston	1982	610.0	610.0	610.0	610.0	610.0	610.0	610.0	610.0	610.0	610.0
A von Rosenberg 1-CT1	BRAUNIG_AVR1_CT1	Bexar	Gas	South	2000	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
A von Rosenberg 1-CT2	BRAUNIG_AVR1_CT2	Bexar	Gas	South	2000	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
A von Rosenberg 1-ST1	BRAUNIG_AVR1_ST	Bexar	Gas	South	2000	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Atkins 7	ATKINS_ATKINSG7	Brazos	Gas	North	1973	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
B M Davis 1	B_DAVIS_B_DAVIG1	Nueces	Gas	South	1974	335.0	335.0	335.0	335.0	335.0	335.0	335.0	335.0	335.0	335.0
B M Davis 2	B_DAVIS_B_DAVIG2	Nueces	Gas	South	1976	319.0	319.0	319.0	319.0	319.0	319.0	319.0	319.0	319.0	319.0
B M Davis 3	B_DAVIS_B_DAVIG3	Nueces	Gas	South	2009	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0
B M Davis 4	B_DAVIS_B_DAVIG4	Nueces	Gas	South	2009	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0
Bastrop Energy Center 1	BASTEN_GTG1100	Bastrop	Gas	South	2002	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Bastrop Energy Center 2	BASTEN_GTG2100	Bastrop	Gas	South	2002	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Bastrop Energy Center 3	BASTEN_ST0100	Bastrop	Gas	South	2002	233.0	233.0	233.0	233.0	233.0	233.0	233.0	233.0	233.0	233.0
Big Spring	CARBN_BSP_1	Howard	Gas	West	2006	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Bosque County Peaking 1	BOSQUESW_BSQSU_1	Bosque	Gas	North	2000	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0
Bosque County Peaking 2	BOSQUESW_BSQSU_2	Bosque	Gas	North	2000	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0
Bosque County Peaking 3	BOSQUESW_BSQSU_3	Bosque	Gas	North	2001	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0
Bosque County Peaking 4	BOSQUESW_BSQSU_4	Bosque	Gas	North	2001	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0
Bosque County Unit 5	BOSQUESW_BSQSU_5	Bosque	Gas	North	2009	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Brazos Valley 1	BVE_UNIT1	Ft Bend	Gas	Houston	2003	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Brazos Valley 2	BVE_UNIT2	Ft Bend	Gas	Houston	2003	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Brazos Valley 3	BVE_UNIT3	Ft Bend	Gas	Houston	2003	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
Calenergy (Falcon Seaboard) 1	FLCNS_UNIT1	Howard	Gas	West	1987	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Calenergy (Falcon Seaboard) 2	FLCNS_UNIT2	Howard	Gas	West	1987	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Calenergy (Falcon Seaboard) 3	FLCNS_UNIT3	Howard	Gas	West	1988	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Cedar Bayou 1	CBY_CBY_G1	Chambers	Gas	Houston	1970	745.0	745.0	745.0	745.0	745.0	745.0	745.0	745.0	745.0	745.0
Cedar Bayou 2	CBY_CBY_G2	Chambers	Gas	Houston	1972	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0
Cedar Bayou 4	CBY4_CT41	Chambers	Gas	Houston	2009	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0
Cedar Bayou 5	CBY4_CT42	Chambers	Gas	Houston	2009	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0
Cedar Bayou 6	CBY4_ST04	Chambers	Gas	Houston	2009	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0
Colorado Bend Energy Center	CBEC_GT1	Wharton	Gas	Houston	2007	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0
Colorado Bend Energy Center	CBEC_GT2	Wharton	Gas	Houston	2007	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0
Colorado Bend Energy Center	CBEC_GT3	Wharton	Gas	Houston	2008	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0
Colorado Bend Energy Center	CBEC_GT4	Wharton	Gas	Houston	2008	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0
Colorado Bend Energy Center	CBEC_STG1	Wharton	Gas	Houston	2007	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0
Colorado Bend Energy Center	CBEC_STG2	Wharton	Gas	Houston	2008	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0
CVC Channelview 1	CVC_CVC_G1	Harris	Gas	Houston	2008	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0
CVC Channelview 2	CVC_CVC_G2	Harris	Gas	Houston	2008	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
CVC Channelview 3	CVC_CVC_G3	Harris	Gas	Houston	2008	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
CVC Channelview 5	CVC_CVC_G5	Harris	Gas	Houston	2008	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0
Dansby 1	DANSBY_DANSBYG1	Brazos	Gas	North	1978	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Dansby 2	DANSBY_DANSBYG2	Brazos	Gas	North	2004	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Dansby 3	DANSBY_DANSBYG3	Brazos	Gas	North	2010	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek 1	DECKER_DPG1	Travis	Gas	South	2000	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0
Decker Creek 2	DECKER_DPG2	Travis	Gas	South	2000	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
Decker Creek G1	DECKER_DPGT_1	Travis	Gas	South	2000	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek G2	DECKER_DPGT_2	Travis	Gas	South	2000	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek G3	DECKER_DPGT_3	Travis	Gas	South	2000	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek G4	DECKER_DPGT_4	Travis	Gas	South	2000	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
DeCordova A	DCSES_CT10	Hood	Gas	North	2010	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
DeCordova B	DCSES_CT20	Hood	Gas	North	2010	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
DeCordova C	DCSES_CT30	Hood	Gas	North	2010	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0
DeCordova D	DCSES_CT40	Hood	Gas	North	2010	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Deer Park Energy Center 1	DDPEC_GT1	Harris	Gas	Houston	2002	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0
Deer Park Energy Center 2	DDPEC_GT2	Harris	Gas	Houston	2002	199.0	199.0	199.0	199.0	199.0	199.0	199.0	199.0	199.0	199.0
Deer Park Energy Center 3	DDPEC_GT3	Harris	Gas	Houston	2002	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0
Deer Park Energy Center 4	DDPEC_GT4	Harris	Gas	Houston	2002	199.0	199.0	199.0	199.0	199.0	199.0	199.0	199.0	199.0	199.0
Deer Park Energy Center S	DDPEC_ST1	Harris	Gas	Houston	2002	290.0	290.0	290.0	290.0	290.0	290.0	290.0	290.0	290.0	290.0
Ennis Power Station 1	ETCCS_UNIT1	Ellis	Gas	North	2002	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0
Ennis Power Station 2	ETCCS_CT1	Ellis	Gas	North	2002	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0
ExTex La Porte Pwr Stn (AirPro) 1	AZ_AZ_G1	Harris	Gas	Houston	2009	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
ExTex La Porte Pwr Stn (AirPro) 2	AZ_AZ_G2	Harris	Gas	Houston	2009	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
ExTex La Porte Pwr Stn (AirPro) 3	AZ_AZ_G3	Harris	Gas	Houston	2009	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
ExTex La Porte Pwr Stn (AirPro) 4	AZ_AZ_G4	Harris	Gas	Houston	2009	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Forney Energy Center GT11	FRNYPP_GT11	Kaufman	Gas	North	2003	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7
Forney Energy Center GT12	FRNYPP_GT12	Kaufman	Gas	North	2003	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7
Forney Energy Center GT13	FRNYPP_GT13	Kaufman	Gas	North	2003	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7
Forney Energy Center GT21	FRNYPP_GT21	Kaufman	Gas	North	2003	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7
Forney Energy Center GT22	FRNYPP_GT22	Kaufman	Gas	North	2003	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7
Forney Energy Center GT23	FRNYPP_GT23	Kaufman	Gas	North	2003	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7	159.7
Forney Energy Center STG10	FRNYPP_ST10	Kaufman	Gas	North	2003	400.9	400.9	400.9	400.9	400.9	400.9	400.9	400.9	400.9	400.9
Forney Energy Center STG20	FRNYPP_ST20	Kaufman	Gas	North	2003	400.9	400.9	400.9	400.9	400.9	400.9	400.9	400.9	400.9	400.9
Freestone Energy Center 1	FREC_GT1	Freestone	Gas	North	2002	151.6	151.6	151.6	151.6	151.6	151.6	151.6	151.6	151.6	151.6
Freestone Energy Center 2	FREC_GT2	Freestone	Gas	North	2002	151.6	151.6	151.6	151.6	151.6	151.6	151.6	151.6	151.6	151.6
Freestone Energy Center 3	FREC_ST3	Freestone	Gas	North	2002	176.2	176.2	176.2	176.2	176.2	176.2	176.2	176.2	176.2	176.2
Freestone Energy Center 4	FREC_GT4	Freestone	Gas	North	2002	151.7	151.7	151.7	151.7	151.7	151.7	151.7	151.7	151.7	151.7
Freestone Energy Center 5	FREC_GT5	Freestone	Gas	North	2002	151.7	151.7	151.7	151.7	151.7	151.7	151.7	151.7	151.7	151.7
Freestone Energy Center 6	FREC_ST6	Freestone	Gas	North	2002	174.5	174.5	174.5	174.5	174.5	174.5	174.5	174.5	174.5	174.5

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Frontera 1	FRONTERA_FRONTEG1	Hidalgo	Gas	South	1999	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Frontera 2	FRONTERA_FRONTEG2	Hidalgo	Gas	South	1999	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Frontera 3	FRONTERA_FRONTEG3	Hidalgo	Gas	South	2000	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0
Graham 1	GRSES_UNIT1	Young	Gas	West	1960	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0
Graham 2	GRSES_UNIT2	Young	Gas	West	1969	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0
Greens Bayou 5	GBY_GBY_5	Harris	Gas	Houston	1973	406.0	406.0	406.0	406.0	406.0	406.0	406.0	406.0	406.0	406.0
Greens Bayou 73	GBY_GBYGT73	Harris	Gas	Houston	1976	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Greens Bayou 74	GBY_GBYGT74	Harris	Gas	Houston	1976	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Greens Bayou 81	GBY_GBYGT81	Harris	Gas	Houston	1976	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Greens Bayou 83	GBY_GBYGT83	Harris	Gas	Houston	1976	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Greens Bayou 84	GBY_GBYGT84	Harris	Gas	Houston	1976	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
Greenville Engine Plant	STEAM_ENGINE_1	Hunt	Gas	North	2010	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Greenville Engine Plant	STEAM_ENGINE_2	Hunt	Gas	North	2010	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Greenville Engine Plant	STEAM_ENGINE_3	Hunt	Gas	North	2010	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Guadalupe Gen Stn 1	GUADG_GAS1	Guadalupe	Gas	South	2000	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0
Guadalupe Gen Stn 2	GUADG_GAS2	Guadalupe	Gas	South	2000	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0
Guadalupe Gen Stn 3	GUADG_GAS3	Guadalupe	Gas	South	2000	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0
Guadalupe Gen Stn 4	GUADG_GAS4	Guadalupe	Gas	South	2000	152.0	152.0	152.0	152.0	152.0	152.0	152.0	152.0	152.0	152.0
Guadalupe Gen Stn 5	GUADG_STM5	Guadalupe	Gas	South	2000	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Guadalupe Gen Stn 6	GUADG_STM6	Guadalupe	Gas	South	2000	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
Handley 3	HLSES_UNIT3	Tarrant	Gas	North	1963	395.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0
Handley 4	HLSES_UNIT4	Tarrant	Gas	North	1976	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0
Handley 5	HLSES_UNIT5	Tarrant	Gas	North	1977	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0
Hays Energy Facility 1	HAYSEN_HAYSENG1	Hays	Gas	South	2002	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
Hays Energy Facility 2	HAYSEN_HAYSENG2	Hays	Gas	South	2002	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
Hays Energy Facility 3	HAYSEN_HAYSENG3	Hays	Gas	South	2002	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0
Hays Energy Facility 4	HAYSEN_HAYSENG4	Hays	Gas	South	2002	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0
Hidalgo 1	DUKE_DUKE_GT1	Hidalgo	Gas	South	2000	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0
Hidalgo 2	DUKE_DUKE_GT2	Hidalgo	Gas	South	2000	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0
Hidalgo 3	DUKE_DUKE_ST1	Hidalgo	Gas	South	2000	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Jack County GenFacility 1	JACKCNTY_CT1	Jack	Gas	North	2005	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Jack County GenFacility 1	JACKCNTY_CT2	Jack	Gas	North	2005	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Jack County GenFacility 1	JACKCNTY_STG	Jack	Gas	North	2005	295.0	295.0	295.0	295.0	295.0	295.0	295.0	295.0	295.0	295.0
Jack County GenFacility 2	JCKCNTY2_CT3	Jack	Gas	North	2011	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Jack County GenFacility 2	JCKCNTY2_CT4	Jack	Gas	North	2011	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Jack County GenFacility 2	JCKCNTY2_ST2	Jack	Gas	North	2011	295.0	295.0	295.0	295.0	295.0	295.0	295.0	295.0	295.0	295.0
Johnson County GenFacility 1	TEN_CT1	Johnson	Gas	North	1997	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0
Johnson County GenFacility 2	TEN_STG	Johnson	Gas	North	1997	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0
Lake Hubbard 1	LHSES_UNIT1	Dallas	Gas	North	1970	392.0	392.0	392.0	392.0	392.0	392.0	392.0	392.0	392.0	392.0
Lake Hubbard 2	LH2SES_UNIT2	Dallas	Gas	North	2010	515.0	515.0	515.0	515.0	515.0	515.0	515.0	515.0	515.0	515.0
Lamar Power Project CT11	LPCCS_CT11	Lamar	Gas	North	2000	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8
Lamar Power Project CT12	LPCCS_CT12	Lamar	Gas	North	2000	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8
Lamar Power Project CT21	LPCCS_CT21	Lamar	Gas	North	2000	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8
Lamar Power Project CT22	LPCCS_CT22	Lamar	Gas	North	2000	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8
Lamar Power Project STG1	LPCCS_UNIT1	Lamar	Gas	North	2000	193.4	193.4	193.4	193.4	193.4	193.4	193.4	193.4	193.4	193.4
Lamar Power Project STG2	LPCCS_UNIT2	Lamar	Gas	North	2000	193.4	193.4	193.4	193.4	193.4	193.4	193.4	193.4	193.4	193.4
Laredo Peaking 4	LARDVFTN_G4	Webb	Gas	South	2008	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2
Laredo Peaking 5	LARDVFTN_G5	Webb	Gas	South	2008	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2
Leon Creek Peaking 1	LEON_CRK_LCPCT1	Bexar	Gas	South	2004	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Leon Creek Peaking 2	LEON_CRK_LCPCT2	Bexar	Gas	South	2004	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Leon Creek Peaking 3	LEON_CRK_LCPCT3	Bexar	Gas	South	2004	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Leon Creek Peaking 4	LEON_CRK_LCPCT4	Bexar	Gas	South	2004	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Lost Pines 1	LOSTPI_LOSTPGT1	Bastrop	Gas	South	2001	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Lost Pines 2	LOSTPI_LOSTPGT2	Bastrop	Gas	South	2001	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Lost Pines 3	LOSTPI_LOSTPST1	Bastrop	Gas	South	2001	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0
Magic Valley 1	NEDIN_NEDIN_G1	Hidalgo	Gas	South	2001	208.6	208.6	208.6	208.6	208.6	208.6	208.6	208.6	208.6	208.6
Magic Valley 2	NEDIN_NEDIN_G2	Hidalgo	Gas	South	2001	208.6	208.6	208.6	208.6	208.6	208.6	208.6	208.6	208.6	208.6
Magic Valley 3	NEDIN_NEDIN_G3	Hidalgo	Gas	South	2001	253.0	253.0	253.0	253.0	253.0	253.0	253.0	253.0	253.0	253.0
Midlothian 1	MDANP_CT1	Ellis	Gas	North	2001	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 2	MDANP_CT2	Ellis	Gas	North	2001	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 3	MDANP_CT3	Ellis	Gas	North	2001	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 4	MDANP_CT4	Ellis	Gas	North	2001	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 5	MDANP_CT5	Ellis	Gas	North	2002	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0
Midlothian 6	MDANP_CT6	Ellis	Gas	North	2002	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0
Morgan Creek A	MGSES_CT1	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek B	MGSES_CT2	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek C	MGSES_CT3	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Morgan Creek D	MGSES_CT4	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek E	MGSES_CT5	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek F	MGSES_CT6	Mitchell	Gas	West	1988	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0
Mountain Creek 6	MCSES_UNIT6	Dallas	Gas	North	1956	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Mountain Creek 7	MCSES_UNIT7	Dallas	Gas	North	1958	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0
Mountain Creek 8	MCSES_UNIT8	Dallas	Gas	North	1967	565.0	565.0	565.0	565.0	565.0	565.0	565.0	565.0	565.0	565.0
Nueces Bay 7	NUECES_B_NUECESG7	Nueces	Gas	South	1972	319.0	319.0	319.0	319.0	319.0	319.0	319.0	319.0	319.0	319.0
Nueces Bay 8	NUECES_B_NUECESG8	Nueces	Gas	South	2009	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0
Nueces Bay 9	NUECES_B_NUECESG9	Nueces	Gas	South	2009	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0
O W Sommers 1	CALAVERS_OWS1	Bexar	Gas	South	1972	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
O W Sommers 2	CALAVERS_OWS2	Bexar	Gas	South	1974	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
Odessa-Ector Gen Stn C11	OECCS_CT11	Ector	Gas	West	2001	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0
Odessa-Ector Gen Stn C12	OECCS_CT12	Ector	Gas	West	2001	140.4	140.4	140.4	140.4	140.4	140.4	140.4	140.4	140.4	140.4
Odessa-Ector Gen Stn C21	OECCS_CT21	Ector	Gas	West	2001	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7
Odessa-Ector Gen Stn C22	OECCS_CT22	Ector	Gas	West	2001	142.4	142.4	142.4	142.4	142.4	142.4	142.4	142.4	142.4	142.4
Odessa-Ector Gen Stn ST1	OECCS_UNIT1	Ector	Gas	West	2001	210.0	210.0	210.0	210.0	210.0	210.0	210.0	210.0	210.0	210.0
Odessa-Ector Gen Stn ST2	OECCS_UNIT2	Ector	Gas	West	2001	210.0	210.0	210.0	210.0	210.0	210.0	210.0	210.0	210.0	210.0
Paris Energy Center 1	TNSKA_GT1	Lamar	Gas	North	1989	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0
Paris Energy Center 2	TNSKA_GT2	Lamar	Gas	North	1989	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0
Paris Energy Center 3	TNSKA_STG	Lamar	Gas	North	1990	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0
PasGen	PSG_PSG_GT2	Harris	Gas	Houston	2000	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
PasGen	PSG_PSG_GT3	Harris	Gas	Houston	2000	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
PasGen	PSG_PSG_ST2	Harris	Gas	Houston	2000	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0
Pearsall 1	PEARSALL_PEARS_1	Frio	Gas	South	1961	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall 2	PEARSALL_PEARS_2	Frio	Gas	South	1961	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall 3	PEARSALL_PEARS_3	Frio	Gas	South	1961	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall Engine Plant	PEARSAL2_AGR_A	Frio	Gas	South	2010	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Pearsall Engine Plant	PEARSAL2_AGR_B	Frio	Gas	South	2010	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Pearsall Engine Plant	PEARSAL2_AGR_C	Frio	Gas	South	2010	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Pearsall Engine Plant	PEARSAL2_AGR_D	Frio	Gas	South	2010	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Permian Basin A	PB2SES_CT1	Ward	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Permian Basin B	PB2SES_CT2	Ward	Gas	West	1988	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Permian Basin C	PB2SES_CT3	Ward	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Permian Basin D	PB2SES_CT4	Ward	Gas	West	1990	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0
Permian Basin E	PB2SES_CT5	Ward	Gas	West	1990	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Powerlane Plant 1	STEAM1A_STEAM_1	Hunt	Gas	North	2009	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Powerlane Plant 2	STEAM_STEAM_2	Hunt	Gas	North	1967	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
Powerlane Plant 3	STEAM_STEAM_3	Hunt	Gas	North	1978	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0
Quail Run Energy GT1	QALSW_GT2	Ector	Gas	West	2007	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
Quail Run Energy GT2	QALSW_GT3	Ector	Gas	West	2008	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0
Quail Run Energy GT3	QALSW_STG1	Ector	Gas	West	2007	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Quail Run Energy GT4	QALSW_STG2	Ector	Gas	West	2008	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Quail Run Energy STG1	QALSW_GT1	Ector	Gas	West	2007	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
Quail Run Energy STG2	QALSW_GT4	Ector	Gas	West	2008	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0
R W Miller 1	MIL_MILLERG1	Palo Pinto	Gas	North	2000	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
R W Miller 2	MIL_MILLERG2	Palo Pinto	Gas	North	2000	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
R W Miller 3	MIL_MILLERG3	Palo Pinto	Gas	North	2000	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0
R W Miller 4	MIL_MILLERG4	Palo Pinto	Gas	North	2000	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
R W Miller 5	MIL_MILLERG5	Palo Pinto	Gas	North	2000	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
Ray Olinger 1	OLINGR_OLING_1	Collin	Gas	North	1967	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0
Ray Olinger 2	OLINGR_OLING_2	Collin	Gas	North	1971	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0
Ray Olinger 3	OLINGR_OLING_3	Collin	Gas	North	1975	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0
Ray Olinger 4	OLINGR_OLING_4	Collin	Gas	North	2001	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Rayburn 1	RAYBURN_RAYBURG1	Victoria	Gas	South	1963	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Rayburn 10	RAYBURN_RAYBURG10	Victoria	Gas	South	2003	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Rayburn 2	RAYBURN_RAYBURG2	Victoria	Gas	South	1963	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Rayburn 7	RAYBURN_RAYBURG7	Victoria	Gas	South	2003	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Rayburn 8	RAYBURN_RAYBURG8	Victoria	Gas	South	2003	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Rayburn 9	RAYBURN_RAYBURG9	Victoria	Gas	South	2003	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Rio Nogales 1	RIONOG_CT1	Guadalupe	Gas	South	2002	154.0	154.0	154.0	154.0	154.0	154.0	154.0	154.0	154.0	154.0
Rio Nogales 2	RIONOG_CT2	Guadalupe	Gas	South	2002	154.0	154.0	154.0	154.0	154.0	154.0	154.0	154.0	154.0	154.0
Rio Nogales 3	RIONOG_CT3	Guadalupe	Gas	South	2002	154.0	154.0	154.0	154.0	154.0	154.0	154.0	154.0	154.0	154.0
Rio Nogales 4	RIONOG_ST1	Guadalupe	Gas	South	2002	323.0	323.0	323.0	323.0	323.0	323.0	323.0	323.0	323.0	323.0
San Jacinto SES 1	SJS_SJS_G1	Harris	Gas	Houston	1995	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
San Jacinto SES 2	SJS_SJS_G2	Harris	Gas	Houston	1995	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Sandhill Energy Center 1	SANDHSYD_SH1	Travis	Gas	South	2001	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Sandhill Energy Center 2	SANDHSYD_SH2	Travis	Gas	South	2001	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sandhill Energy Center 3	SANDHSYD_SH3	Travis	Gas	South	2001	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Sandhill Energy Center 4	SANDHSYD_SH4	Travis	Gas	South	2001	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Sandhill Energy Center 5A	SANDHSYD_SH_5A	Travis	Gas	South	2004	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Sandhill Energy Center 5C	SANDHSYD_SH_5C	Travis	Gas	South	2004	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0
Sandhill Energy Center 6	SANDHSYD_SH6	Travis	Gas	South	2010	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Sandhill Energy Center 7	SANDHSYD_SH7	Travis	Gas	South	2010	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Silas Ray 10	SILASRAY_SILAS_10	Cameron	Gas	South	2004	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Silas Ray 6	SILASRAY_SILAS_6	Cameron	Gas	South	1961	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Silas Ray 9	SILASRAY_SILAS_9	Cameron	Gas	South	1996	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Sim Gideon 1	GIDEON_GIDEONG1	Bastrop	Gas	South	1965	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Sim Gideon 2	GIDEON_GIDEONG2	Bastrop	Gas	South	1968	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0
Sim Gideon 3	GIDEON_GIDEONG3	Bastrop	Gas	South	1972	332.0	332.0	332.0	332.0	332.0	332.0	332.0	332.0	332.0	332.0
Spencer 4	SPNCER_SPNCE_4	Denton	Gas	North	1966	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0
Spencer 5	SPNCER_SPNCE_5	Denton	Gas	North	1973	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0
SR Bertron	SRB_SRB_G1	Harris	Gas	Houston	1958	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
SR Bertron	SRB_SRB_G2	Harris	Gas	Houston	1956	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0
SR Bertron	SRB_SRB_G3	Harris	Gas	Houston	1959	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0
SR Bertron	SRB_SRB_G4	Harris	Gas	Houston	1960	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0
SR Bertron	SRB_SRBGT_2	Harris	Gas	Houston	1967	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Stryker Creek 1	SCSES_UNIT1A	Cherokee	Gas	North	1958	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0
Stryker Creek 2	SCSES_UNIT2	Cherokee	Gas	North	1965	502.0	502.0	502.0	502.0	502.0	502.0	502.0	502.0	502.0	502.0
Thomas C Ferguson 1	FERGUS_FERGUSG1	Llano	Gas	South	1974	354.0	354.0	354.0	354.0	354.0	354.0	354.0	354.0	354.0	354.0
T H Wharton 3	THW_THWST_3	Harris	Gas	Houston	1974	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
T H Wharton 31	THW_THWGT31	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 32	THW_THWGT32	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 33	THW_THWGT33	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 34	THW_THWGT34	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 4	THW_THWST_4	Harris	Gas	Houston	1974	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
T H Wharton 41	THW_THWGT41	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 42	THW_THWGT42	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 43	THW_THWGT43	Harris	Gas	Houston	1974	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 44	THW_THWGT44	Harris	Gas	Houston	1974	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 51	THW_THWGT51	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 52	THW_THWGT52	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 53	THW_THWGT53	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 54	THW_THWGT54	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 55	THW_THWGT55	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 56	THW_THWGT56	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton G1	THW_THWGT_1	Harris	Gas	Houston	1967	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Texas City 1	TXCTY_CTA	Galveston	Gas	Houston	2000	96.6	96.6	96.6	96.6	96.6	96.6	96.6	96.6	96.6	96.6
Texas City 2	TXCTY_CTB	Galveston	Gas	Houston	2000	96.6	96.6	96.6	96.6	96.6	96.6	96.6	96.6	96.6	96.6
Texas City 3	TXCTY_CTC	Galveston	Gas	Houston	2000	96.6	96.6	96.6	96.6	96.6	96.6	96.6	96.6	96.6	96.6
Texas City 4	TXCTY_ST	Galveston	Gas	Houston	2000	131.6	131.6	131.6	131.6	131.6	131.6	131.6	131.6	131.6	131.6
Texas Gulf Sulphur	TGF_TGFGT_1	Wharton	Gas	Houston	1985	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
Trinidad 6	TRSES_UNIT6	Henderson	Gas	North	1965	226.0	226.0	226.0	226.0	226.0	226.0	226.0	226.0	226.0	226.0
V H Braunig 1	BRAUNIG_VHB1	Bexar	Gas	South	1966	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
V H Braunig 2	BRAUNIG_VHB2	Bexar	Gas	South	1968	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0
V H Braunig 3	BRAUNIG_VHB3	Bexar	Gas	South	1970	412.0	412.0	412.0	412.0	412.0	412.0	412.0	412.0	412.0	412.0
V H Braunig 5	BRAUNIG_VHB6CT5	Bexar	Gas	South	2009	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
V H Braunig 6	BRAUNIG_VHB6CT6	Bexar	Gas	South	2009	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
V H Braunig 7	BRAUNIG_VHB6CT7	Bexar	Gas	South	2009	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
V H Braunig 8	BRAUNIG_VHB6CT8	Bexar	Gas	South	2009	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Victoria Power Station 5	VICTORIA_VICTORG5	Victoria	Gas	South	2009	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Victoria Power Station 6	VICTORIA_VICTORG6	Victoria	Gas	South	2009	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
W A Parish 1	WAP_WAP_G1	Ft. Bend	Gas	Houston	1958	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
W A Parish 2	WAP_WAP_G2	Ft. Bend	Gas	Houston	1958	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
W A Parish 3	WAP_WAP_G3	Ft. Bend	Gas	Houston	1961	258.0	258.0	258.0	258.0	258.0	258.0	258.0	258.0	258.0	258.0
W A Parish 4	WAP_WAP_G4	Ft. Bend	Gas	Houston	1968	552.0	552.0	552.0	552.0	552.0	552.0	552.0	552.0	552.0	552.0
W A Parish T1	WAP_WAPGT_1	Ft. Bend	Gas	Houston	1967	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Wichita Falls 1	WFCOGEN_UNIT1	Wichita	Gas	West	1987	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Wichita Falls 2	WFCOGEN_UNIT2	Wichita	Gas	West	1987	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Wichita Falls 3	WFCOGEN_UNIT3	Wichita	Gas	West	1987	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Wichita Falls 4	WFCOGEN_UNIT4	Wichita	Gas	West	1987	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
Winchester Power Park 1	WIPOPA_WPP_G1	Fayette	Gas	South	2010	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Winchester Power Park 2	WIPOPA_WPP_G2	Fayette	Gas	South	2010	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Winchester Power Park 3	WIPOPA_WPP_G3	Fayette	Gas	South	2010	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Winchester Power Park 4	WIPOPA_WPP_G4	Fayette	Gas	South	2010	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Wise-Tractebel Power Proj. 1	WCPP_CT1	Wise	Gas	North	2004	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0
Wise-Tractebel Power Proj. 2	WCPP_CT2	Wise	Gas	North	2004	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0
Wise-Tractebel Power Proj. 3	WCPP_ST1	Wise	Gas	North	2004	241.0	241.0	241.0	241.0	241.0	241.0	241.0	241.0	241.0	241.0
Wolf Hollow Power Proj. 1	WHCCS_CT1	Hood	Gas	North	2002	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5
Wolf Hollow Power Proj. 2	WHCCS_CT2	Hood	Gas	North	2002	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5
Wolf Hollow Power Proj. 3	WHCCS_STG	Hood	Gas	North	2002	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
Canyon	CANYHY_CANYHYG1	Comal	Hydro	South	1989	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Eagle Pass Hydro	EAGLE_HY_EAGLE_HY1	Maverick	Hydro	South	1932	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Lakewood Tap	DG_LKWDT_2UNITS	Gonzales	Hydro	South	1931	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Lewisville	DG_LWSVL_1UNIT	Denton	Hydro	North	1991	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
McQueeney	DG_MCQUE_5UNITS	Guadalupe	Hydro	South	1928	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Schumansville	DG_SCHUM_2UNITS	Guadalupe	Hydro	South	1928	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Amistad Hydro 1	AMISTAD_AMISTAG1	Val Verde	Hydro	South	1983	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9
Amistad Hydro 2	AMISTAD_AMISTAG2	Val Verde	Hydro	South	1983	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9
Austin 1	AUSTPL_AUSTING1	Travis	Hydro	South	1940	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Austin 2	AUSTPL_AUSTING2	Travis	Hydro	South	1940	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Buchanan 1	BUCHAN_BUCHANG1	Llano	Hydro	South	1938	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Buchanan 2	BUCHAN_BUCHANG2	Llano	Hydro	South	1938	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Buchanan 3	BUCHAN_BUCHANG3	Llano	Hydro	South	1950	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
Denison Dam 1	DNDAM_DENISOG1	Grayson	Hydro	North	1944	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Denison Dam 2	DNDAM_DENISOG2	Grayson	Hydro	North	1948	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Falcon Hydro 1	FALCON_FALCONG1	Starr	Hydro	South	1954	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Falcon Hydro 2	FALCON_FALCONG2	Starr	Hydro	South	1954	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Falcon Hydro 3	FALCON_FALCONG3	Starr	Hydro	South	1954	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Granite Shoals 1	WIRTZ_WIRTZ_G1	Burnet	Hydro	South	1951	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Granite Shoals 2	WIRTZ_WIRTZ_G2	Burnet	Hydro	South	1951	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Inks 1	INKSDA_INKS_G1	Llano	Hydro	South	1938	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Marble Falls 1	MARBFA_MARBFAG1	Burnet	Hydro	South	1951	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Marble Falls 2	MARBFA_MARBFAG2	Burnet	Hydro	South	1951	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Marshall Ford 1	MARSFO_MARSFOG1	Travis	Hydro	South	1941	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Marshall Ford 2	MARSFO_MARSFOG2	Travis	Hydro	South	1941	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Marshall Ford 3	MARSFO_MARSFOG3	Travis	Hydro	South	1941	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Whitney 2	WND_WHITNEY2	Bosque	Hydro	North	1953	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Comanche Peak 1	CPSES_UNIT1	Somervell	Nuclear	North	1990	1205.0	1205.0	1205.0	1205.0	1205.0	1205.0	1205.0	1205.0	1205.0	1205.0
Comanche Peak 2	CPSES_UNIT2	Somervell	Nuclear	North	1993	1195.0	1195.0	1195.0	1195.0	1195.0	1195.0	1195.0	1195.0	1195.0	1195.0
South Texas 1	STP_STP_G1	Matagorda	Nuclear	South	1988	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0
South Texas 2	STP_STP_G2	Matagorda	Nuclear	South	1989	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0
NoTrees Battery	NWF_NBS	Winkler	Storage	West	2012	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
AES Deepwater	APD_APD_PS1	Harris	Storage	Houston	2010	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Kmaybto	DG_KMASB_1UNIT	Wichita	Other	North	2011	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Blue Wing 1	DG_BROOK_1UNIT	Bexar	Solar	South	2010	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Blue Wing 2	DG_ELMEN_1UNIT	Bexar	Solar	South	2010	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Somerset 1	DG_SOME1_1UNIT	Bexar	Solar	South	2012	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Somerset 2	DG_SOME2_1UNIT	Bexar	Solar	South	2012	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Sunedison Rabel Road	DG_VALL1_1UNIT	Bexar	Solar	South	2012	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Sunedison Valley Road	DG_VALL2_1UNIT	Bexar	Solar	South	2012	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Webberville	WEBBER_S_WSP1	Travis	Solar	South	2011	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5
Operational Units Total						**64,997.9**	**64,997.9**	**64,997.9**	**64,997.9**	**64,997.9**	**64,997.9**	**64,997.9**	**64,997.9**	**64,997.9**	**64,997.9**
Generation from Private Use Networks			Gas			**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**
RMR Units Total						**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
DC-Ties															
Eagle Pass	DC_S	Maverick	Other	South		36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
East	DC_E	Fannin	Other	North		600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
Laredo VFT	DC_L	Webb	Other	South		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
North	DC_N	Wilbarger	Other	West		220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
Sharyland (Railroad)	DC_R	Hidalgo	Other	South		150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Sharyland (New Railroad Tie)	DC_R2	Hidalgo	Other	South		150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
DC-Ties Total						**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**
Switchable Resources															
Kiamichi Energy Facility 1CT101	KMCHI_1CT101	Fannin	Gas	North	2003	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0
Kiamichi Energy Facility 1CT201	KMCHI_1CT201	Fannin	Gas	North	2003	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
Kiamichi Energy Facility 1ST	KMCHI_1ST	Fannin	Gas	North	2003	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0
Kiamichi Energy Facility 2CT101	KMCHI_2CT101	Fannin	Gas	North	2003	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Kiamichi Energy Facility 2CT201	KMCHI_2CT201	Fannin	Gas	North	2003	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
Kiamichi Energy Facility 2ST	KMCHI_2ST	Fannin	Gas	North	2003	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0	315.0
Tenaska-Frontier 1	FTR_FTR_G1	Grimes	Gas	North	2000	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Tenaska-Frontier 2	FTR_FTR_G2	Grimes	Gas	North	2000	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Tenaska-Frontier 3	FTR_FTR_G3	Grimes	Gas	North	2000	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Tenaska-Frontier 4	FTR_FTR_G4	Grimes	Gas	North	2000	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0
Tenaska-Gateway 1	TGCCS_CT1	Rusk	Gas	North	2001	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0
Tenaska-Gateway 2	TGCCS_CT2	Rusk	Gas	North	2001	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0
Tenaska-Gateway 3	TGCCS_CT3	Rusk	Gas	North	2001	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0
Tenaska-Gateway 4	TGCCS_UNIT4	Rusk	Gas	North	2001	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0
Switchable Resources Total						**2,977.0**	**2,977.0**	**2,977.0**	**2,977.0**	**2,977.0**	**2,977.0**	**2,977.0**	**2,977.0**	**2,977.0**	**2,977.0**
Wind Resources															
Anacacho Windfarm	ANACACHO_ANA	Kinney	Wind	South	2013	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
Barton Chapel Wind	BRTSW_BCW1	Jack	Wind	North	2007	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Bobcat Wind	BCATWIND_WIND_1	Clay	Wind	North	2013	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0
Buffalo Gap Wind Farm 1	BUFF_GAP_UNIT1	Taylor	Wind	West	2006	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
Buffalo Gap Wind Farm 2	BUFF_GAP_UNIT2_1	Taylor	Wind	West	2007	115.5	115.5	115.5	115.5	115.5	115.5	115.5	115.5	115.5	115.5
Buffalo Gap Wind Farm 2	BUFF_GAP_UNIT2_2	Taylor	Wind	West	2007	117	117	117	117	117	117	117	117	117	117
Buffalo Gap Wind Farm 3	BUFF_GAP_UNIT3	Taylor	Wind	West	2008	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Bull Creek Wind Plant	BULLCRK_WND1	Borden	Wind	West	2009	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0
Bull Creek Wind Plant	BULLCRK_WND2	Borden	Wind	West	2009	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Callahan Wind	CALLAHAN_WND1	Callahan	Wind	West	2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Camp Springs 1	CSEC_CSECG1	Scurry	Wind	West	2007	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0
Camp Springs 2	CSEC_CSECG2	Scurry	Wind	West	2007	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Capricorn Ridge Wind 1	CAPRIDGE_CR1	Sterling	Wind	West	2007	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0
Capricorn Ridge Wind 2	CAPRIDGE_CR3	Sterling	Wind	West	2008	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0
Capricorn Ridge Wind 3	CAPRIDGE_CR2	Sterling	Wind	West	2007	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Capricorn Ridge Wind 4	CAPRIDG4_CR4	Sterling	Wind	West	2008	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
Cedro Hill Wind	CEDROHIL_CHW1	Webb	Wind	South	2010	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Champion Wind Farm	CHAMPION_UNIT1	Nolan	Wind	West	2008	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0
Delaware Mountain Wind Farm	KUNITZ_WIND_NWP	Culberson	Wind	West	2010	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Desert Sky Wind Farm 1	INDNENR_INDNENR	Pecos	Wind	West	2002	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0
Desert Sky Wind Farm 2	INDNENR_INDNENR_2	Pecos	Wind	West	2002	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
Elbow Creek Wind Project	ELB_ELBCREEK	Howard	Wind	West	2008	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0
Forest Creek Wind Farm	MCDLD_FCW1	Glasscock	Wind	West	2007	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Goat Wind	GOAT_GOATWIND	Sterling	Wind	West	2008	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Goat Wind 2	GOAT_GOATWIN2	Sterling	Wind	West	2010	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Green Mountain Energy 1	BRAZ_WND_WND1	Scurry	Wind	West	2003	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0
Green Mountain Energy 2	BRAZ_WND_WND2	Scurry	Wind	West	2003	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0
Gulf Wind I	TGW_T1	Kenedy	Wind	South	2010	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0
Gulf Wind II	TGW_T2	Kenedy	Wind	South	2010	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0
Hackberry Wind Farm	HWF_HWFG1	Shackelford	Wind	West	2008	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0
Harbor Wind	DG_NUECE_6UNITS	Nueces	Wind	South	2012	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Horse Hollow Wind 1	H_HOLLOW_WND1	Taylor	Wind	West	2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Horse Hollow Wind 1	HHGT_HHOLLOW1	Kendall	Wind	South	2009	213.0	213.0	213.0	213.0	213.0	213.0	213.0	213.0	213.0	213.0
Horse Hollow Wind 2	HHOLLOW2_WIND1	Taylor	Wind	West	2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Horse Hollow Wind 2	HHGT_HHOLLOW2	Kendall	Wind	South	2009	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0
Horse Hollow Wind 3	HHOLLOW3_WND_1	Taylor	Wind	West	2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Horse Hollow Wind 3	HHGT_HHOLLOW3	Kendall	Wind	South	2009	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0
Horse Hollow Wind 4	HHOLLOW4_WND1	Taylor	Wind	West	2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Horse Hollow Wind 4	HHGT_HHOLLOW4	Kendall	Wind	South	2009	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0
Horse Hollow Wind Callahan	HHGT_CALLAHAN	Kendall	Wind	South	2009	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0
Inadale Wind	INDL_INADALE1	Nolan	Wind	West	2008	197.0	197.0	197.0	197.0	197.0	197.0	197.0	197.0	197.0	197.0
Indian Mesa Wind Farm	INDNNWP_INDNNWP	Pecos	Wind	West	2001	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0
King Mountain NE	KING_NE_KINGNE	Upton	Wind	West	2001	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
King Mountain NW	KING_NW_KINGNW	Upton	Wind	West	2001	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
King Mountain SE	KING_SE_KINGSE	Upton	Wind	West	2001	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
King Mountain SW	KING_SW_KINGSW	Upton	Wind	West	2001	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
Kunitz Wind	KUNITZ_WIND_LGE	Culberson	Wind	West	1995	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Langford Wind Power	LGD_LANGFORD	Tom Green	Wind	West	2009	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
Loraine Windpark I	LONEWOLF_G1	Mitchell	Wind	West	2009	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Loraine Windpark II	LONEWOLF_G2	Mitchell	Wind	West	2009	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Loraine Windpark III	LONEWOLF_G3	Mitchell	Wind	West	2011	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
Loraine Windpark IV	LONEWOLF_G4	Mitchell	Wind	West	2011	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Magic Valley Wind	REDFISH_MV1A	Willacy	Wind	South	2012	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0
Magic Valley Wind	REDFISH_MV1B	Willacy	Wind	South	2012	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
McAdoo Wind Farm	MWEC_G1	Dickens	Wind	West	2008	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Mesquite Wind	LNCRK_G83	Shackelford	Wind	West	2006	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Notrees-1	NWF_NWF1	Winkler	Wind	West	2009	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0
Ocotillo Wind Farm	OWF_OWF	Howard	Wind	West	2008	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Panther Creek 1	PC_NORTH_PANTHER1	Howard	Wind	West	2008	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0
Panther Creek 2	PC_SOUTH_PANTHER2	Howard	Wind	West	2008	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0
Panther Creek 3	PC_SOUTH_PANTHER3	Howard	Wind	West	2009	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Papalote Creek Wind	COTTON_PAP2	San Patricio	Wind	South	2010	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Papalote Creek Wind Farm	PAP1_PAP1	San Patricio	Wind	South	2009	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Pecos Wind (Woodward 1)	WOODWRD1_WOODWRD1	Pecos	Wind	West	2001	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0
Pecos Wind (Woodward 2)	WOODWRD2_WOODWRD2	Pecos	Wind	West	2001	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
Penascal Wind	PENA_UNIT1	Kenedy	Wind	South	2009	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0
Penascal Wind	PENA_UNIT2	Kenedy	Wind	South	2009	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0
Penascal Wind	PENA3_UNIT3	Kenedy	Wind	South	2010	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
Post Oak Wind 1	LNCRK2_G871	Shackelford	Wind	West	2007	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Post Oak Wind 2	LNCRK2_G872	Shackelford	Wind	West	2007	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Pyron Wind Farm	PYR_PYRON1	Scurry	Wind	West	2008	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0
Red Canyon	RDCANYON_RDCNY1	Borden	Wind	West	2006	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0
Roscoe Wind Farm	TKWSW1_ROSCOE	Nolan	Wind	West	2008	209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0
Sand Bluff Wind Farm	MCDLD_SBW1	Glasscock	Wind	West	2008	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Senate Wind Project	SENATEWD_UNIT1	Jack	Wind	West	2013	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Sherbino 2	KEO_SHRBINO2	Pecos	Wind	West	2012	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Sherbino I	KEO_KEO_SM1	Pecos	Wind	West	2008	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Silver Star	FLTCK_SSI	Eastland	Wind	North	2008	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Snyder Wind Farm	ENAS_ENA1	Scurry	Wind	West	2007	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0
South Trent Wind Farm	STWF_T1	Nolan	Wind	West	2008	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
Stanton Wind Energy	SWEC_G1	Martin	Wind	West	2008	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Sweetwater Wind 1	SWEETWND_WND1	Nolan	Wind	West	2003	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Sweetwater Wind 2	SWEETWN2_WND24	Nolan	Wind	West	2006	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Sweetwater Wind 3	SWEETWN2_WND2	Nolan	Wind	West	2004	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Sweetwater Wind 4	SWEETWN3_WND3A	Nolan	Wind	West	2005	29.5	29.5	29.5	29.5	29.5	29.5	29.5	29.5	29.5	29.5
Sweetwater Wind 4	SWEETWN3_WND3B	Nolan	Wind	West	2005	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5
Sweetwater Wind 5	SWEETWN4_WND5	Nolan	Wind	West	2007	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
Sweetwater Wind 6	SWEETWN4_WND4B	Nolan	Wind	West	2007	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
Sweetwater Wind 7	SWEETWN4_WND4A	Nolan	Wind	West	2007	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
Texas Big Spring	SGMTN_SIGNALMT	Howard	Wind	West	1999	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Trent Wind Farm	TRENT_TRENT	Nolan	Wind	West	2001	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0
Trinity Hills	TRINITY_TH1_BUS1	Young	Wind	North	2012	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
Trinity Hills	TRINITY_TH1_BUS2	Young	Wind	North	2012	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
TSTC West Texas Wind	DG_ROSC2_1UNIT	Nolan	Wind	West	2008	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Turkey Track Wind Energy Center	TTWEC_G1	Nolan	Wind	West	2008	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
West Texas Wind Energy	SW_MESA_SW_MESA	Upton	Wind	West	1999	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
Whirlwind Energy	WEC_WECG1	Floyd	Wind	West	2007	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
Whitetail Wind Energy Project	EXGNWTL_WIND_1	Webb	Wind	South	2013	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0
WKN Mozart	MOZART_WIND_1	Kent	Wind	West	2013	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Wolfe Ridge	WHTTAIL_WR1	Cooke	Wind	North	2008	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
Wind Resources Total						**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**
New Units with Signed IA and Air Permit															
WA Parish Addition	12INR0086	Fort Bend	Gas			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Sandy Creek 1	SCES_UNIT1	McLennan	Coal			925.0	925.0	925.0	925.0	925.0	925.0	925.0	925.0	925.0	925.0
Deepwater Energy Storage	10INR0089	Harris	Storage			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
OCI Alamo 1	13INR0058	Bexar	Solar			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Panda Sherman Power	10INR0021	Grayson	Gas			720.2	720.2	720.2	720.2	720.2	720.2	720.2	720.2	720.2	720.2
Panda Temple Power	10INR0020a	Bell	Gas			717.0	717.0	717.0	717.0	717.0	717.0	717.0	717.0	717.0	717.0
Deer Park Energy Center	14INR0015	Harris	Gas			195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0
Channel Energy Center 138/345kV CT	14INR0016	Harris	Gas			190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Ferguson Replacement Project	13INR0021	Llano	Gas			-	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0
Antelope Station	13INR0028	Hale	Gas			-	-	364.0	364.0	364.0	364.0	364.0	364.0	364.0	364.0
Texas Clean Energy Project	13INR0023	Ector	Coal			-	-	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0
Panda Temple Power	10INR0020b	Bell	Gas			-	-	780.0	780.0	780.0	780.0	780.0	780.0	780.0	780.0
Pondera King Power Project	10INR0022	Harris	Gas			-	-		1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0
New Units Total						**2,927**	**3,497**	**4,881**	**6,261**	**6,261**	**6,261**	**6,261**	**6,261**	**6,261**	**6,261**
New Wind Generation															
Los Vientos	11INR0033	Cameron	Wind			402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0
Blue Summit Windfarm	12INR0075	Wilbarger	Wind			135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Stephens Ranch Wind Energy	12INR0034	Borden	Wind			378.0	378.0	378.0	378.0	378.0	378.0	378.0	378.0	378.0	378.0
Goldthwaite Wind Energy	11INR0013	Mills	Wind			150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Spinning Spur Wind Two	13INR0048	Oldham	Wind			161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0
Mariah Wind	13INR0010b	Parmer	Wind			200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Panhandle Wind	14INR0030a2	Carson	Wind			322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0
Miami Wind 1 Project	14INR0012	Gray	Wind			401.0	401.0	401.0	401.0	401.0	401.0	401.0	401.0	401.0	401.0
Moore Wind 1	11INR0050	Crosby	Wind			-	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0
Mariah Wind	13INR0010a	Parmer	Wind			-	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Midway Farms Wind	11INR0054	San Patricio	Wind			-	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0
Longhorn Energy Center	14INR0023	Briscoe	Wind			-	361.0	361.0	361.0	361.0	361.0	361.0	361.0	361.0	361.0
Conway Windfarm	13INR0005	Carson	Wind			-	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
South Clay Windfarm	11INR0079a	Clay	Wind			-	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Penascal Wind Farm 3	06INR0022c	Kenedy	Wind			-	202.0	202.0	202.0	202.0	202.0	202.0	202.0	202.0	202.0
Mariah Wind	13INR0010c	Parmer	Wind			-	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Mesquite Creek	09INR0051	Borden	Wind			-	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0
Gunsight Mountain	08INR0018	Howard	Wind			-	-	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
New Wind Generation Total						**2,149.0**	**4,471.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**
Switchable Units Unavailable to ERCOT			Gas			**(317.0)**	**(317.0)**	**(317.0)**	**(317.0)**	**(317.0)**	**(317.0)**	**(317.0)**	**-**	**-**	**-**
Retiring Units															
J T Deely 1	CALAVERS_JTD1	Bexar	Coal	South		0.00	0.00	0.00	0.00	0.00	-425.00	-425.00	-425.00	-425.00	-425.00
J T Deely 2	CALAVERS_JTD2	Bexar	Coal	South		0.00	0.00	0.00	0.00	0.00	-420.00	-420.00	-420.00	-420.00	-420.00
Thomas C Ferguson 1	FERGUS_FERGUSG1	Llano	Gas	South		-354.0	-354.0	-354.0	-354.0	-354.0	-354.0	-354.0	-354.0	-354.0	-354.0
Total Retiring Units						**(354.0)**	**(354.0)**	**(354.0)**	**(354.0)**	**(354.0)**	**(1,199.0)**	**(1,199.0)**	**(1,199.0)**	**(1,199.0)**	**(1,199.0)**
Mothballed Resources															
Applied Energy	APD_APD_G1	Harris	Other	Houston	1986	138	138	138	138	138	138	138	138	138	138
Atkins	ATKINS_ATKINSG3	Brazos	Gas	North	1954	12	12	12	12	12	12	12	12	12	12
Atkins	ATKINS_ATKINSG4	Brazos	Gas	North	1958	22	22	22	22	22	22	22	22	22	22
Atkins	ATKINS_ATKINSG5	Brazos	Gas	North	1965	25	25	25	25	25	25	25	25	25	25
Atkins	ATKINS_ATKINSG6	Brazos	Gas	North	1969	50	50	50	50	50	50	50	50	50	50
Greens Bayou	GBY_GBYGT82	Harris	Gas	Houston	1976	58	58	58	58	58	58	58	58	58	58
North Texas	NTX_NTX_1	Parker	Gas	North	1958	18	18	18	18	18	18	18	18	18	18
North Texas	NTX_NTX_2	Parker	Gas	North	1958	18	18	18	18	18	18	18	18	18	18
North Texas	NTX_NTX_3	Parker	Gas	North	1963	39	39	39	39	39	39	39	39	39	39
Permian Basin Ses	PBSES_UNIT6	Ward	Gas	West	2009	515	515	515	515	515	515	515	515	515	515
Silas Ray	SILASRAY_SILAS_5	Cameron	Gas	South	1951	10	10	10	10	10	10	10	10	10	10
Valley SES	VLSES_UNIT1	Fannin	Gas	North	1962	174	174	174	174	174	174	174	174	174	174
Valley SES	VLSES_UNIT2	Fannin	Gas	North	1967	520	520	520	520	520	520	520	520	520	520
Valley SES	VLSES_UNIT3	Fannin	Gas	North	1971	375	375	375	375	375	375	375	375	375	375
Whitney Dam	WND_WHITNEY1	Bosque	Hydro	North	1953	20	20	20	20	20	20	20	20	20	20
Mothballed Resources Total						**1,994**	**1,994**	**1,994**	**1,994**	**1,994**	**1,994**	**1,994**	**1,994**	**1,994**	**1,994**
Excluded Resources, per notification from developer															
Cobisa-Greenville	06INR0006	Hunt	Gas						1,792.0	1,792.0	1,792.0	1,792.0	1,792.0	1,792.0	1,792.0

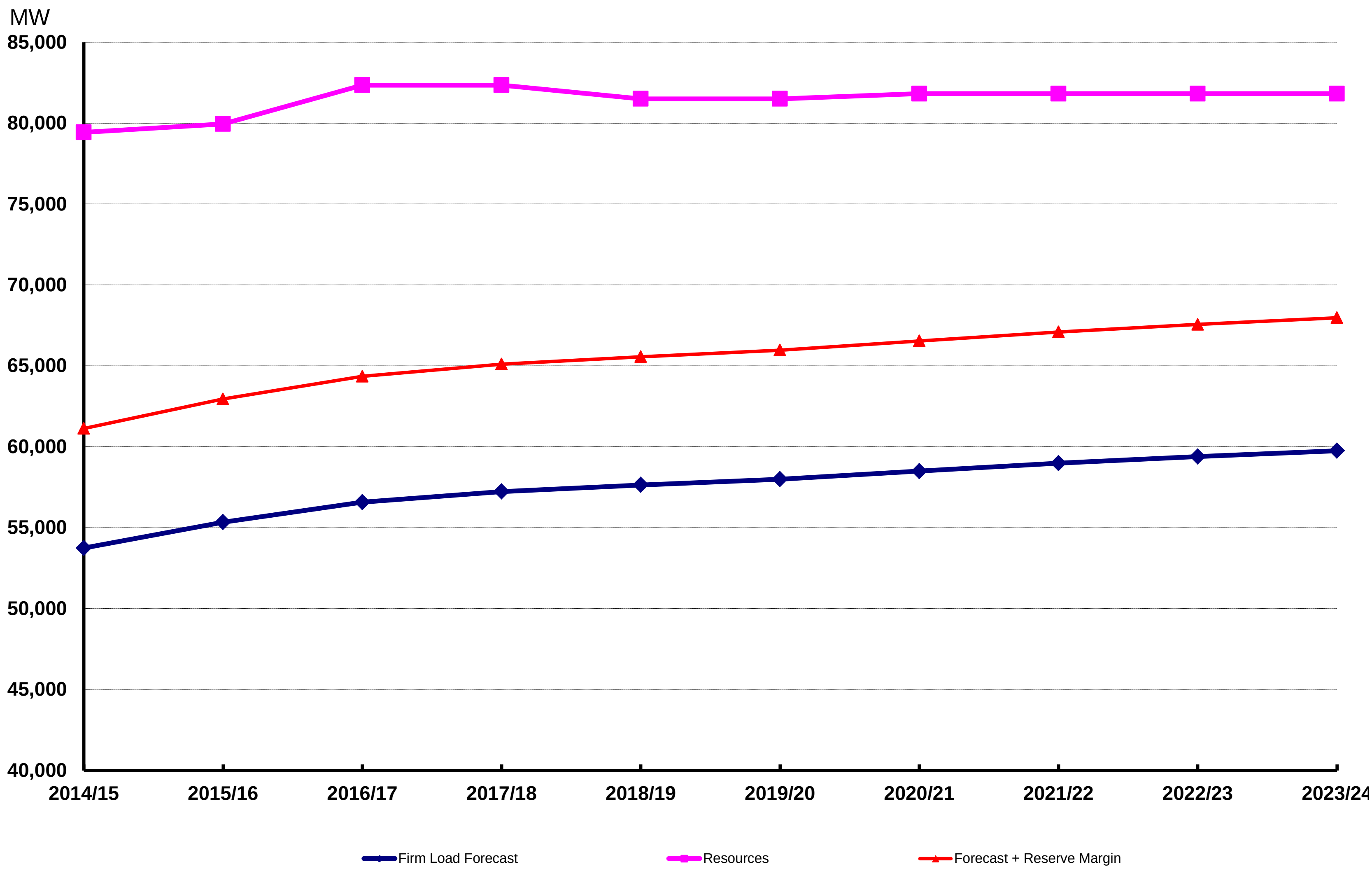
2013 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Winter Summary

Load Forecast:	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Total Winter Peak Demand, MW	55,957	57,738	59,151	60,004	60,612	61,176	61,769	62,358	62,870	63,339
less LRS Serving as Responsive Reserve, MW	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222	1,222
less LRS Serving as Non-Spinning Reserve, MW	0	0	0	0	0	0	0	0	0	0
less Emergency Response Service	475	523	575	632	696	765	842	926	1019	1121
less Energy Efficiency Programs (per Utilities Code Section 39.905 (b-4))	518	648	781	917	1054	1193	1210	1225	1238	1238
Firm Load Forecast, MW	**53,742**	**55,346**	**56,573**	**57,232**	**57,640**	**57,996**	**58,495**	**58,985**	**59,391**	**59,758**
Resources:	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**
Installed Capacity, MW	67,225	67,225	67,225	67,225	67,225	67,225	67,225	67,225	67,225	67,225
Capacity from Private Networks, MW	4,331	4,331	4,331	4,331	4,331	4,331	4,331	4,331	4,331	4,331
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	920	920	920	920	920	920	920	920	920	920
RMR Units to be under Contract, MW	0	0	0	0	0	0	0	0	0	0
Operational Generation, MW	**72,476**	**72,476**	**72,476**	**72,476**	**72,476**	**72,476**	**72,476**	**72,476**	**72,476**	**72,476**
50% of Non-Synchronous Ties, MW	628	628	628	628	628	628	628	628	628	628
Switchable Units, MW	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168
Available Mothballed Generation , MW	6	29	29	29	29	29	29	29	29	29
Planned Units (not wind) with Signed IA and Air Permit, MW	3,624	3,988	6,388	6,388	6,388	6,388	6,388	6,388	6,388	6,388
ELCC of Planned Wind Units with Signed IA, MW	263	399	399	399	399	399	399	399	399	399
Total Resources, MW	**80,164**	**80,688**	**83,088**	**83,088**	**83,088**	**83,088**	**83,088**	**83,088**	**83,088**	**83,088**
less Switchable Units Unavailable to ERCOT, MW	-317	-317	-317	-317	-317	-317	0	0	0	0
less Retiring Units, MW	-425	-425	-425	-425	-1,270	-1,270	-1,270	-1,270	-1,270	-1,270
Resources, MW	**79,422**	**79,946**	**82,346**	**82,346**	**81,501**	**81,501**	**81,818**	**81,818**	**81,818**	**81,818**
Reserve Margin	**47.8%**	**44.4%**	**45.6%**	**43.9%**	**41.4%**	**40.5%**	**39.9%**	**38.7%**	**37.8%**	**36.9%**
(Resources - Firm Load Forecast)/Firm Load Forecast										

2013 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Winter Loads and Resources



Unit Capacities - Winter

Units used in determining the generation resources in the Winter Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Alvin	AV_DG1	Galveston	Biomass	Houston	2002	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Austin Landfill Gas	DG_SPRIN_4UNITS	Travis	Biomass	South	2007	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Covel Gardens Power Station	DG_MEDIN_1UNIT	Bexar	Biomass	South	2005	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
DFW Gas Recovery	DG_BIO2_4UNITS	Denton	Biomass	North	2009	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
DG_Bioenergy Partners	DG_BIOE_2UNITS	Denton	Biomass	North	1988	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Farmer's Branch Landfill	DG_HBR	Denton	Biomass	North	2011	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
FW Region Gen Facility	DG_RDLML_1UNIT	Tarrant	Biomass	North	2006	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Humble	HB_DG1	Harris	Biomass	Houston	2002	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Liberty	LB_DG1	Harris	Biomass	Houston	2002	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Lufkin Biomass	LFBIO_UNIT1	Angelina	Biomass	North	2011	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
McKinney Landfill	DG_MKNSW_2UNITS	Collin	Biomass	North	2011	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Mesquite Creek Energy	DG_FREIH_2UNITS	Comal	Biomass	South	2010	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Nacogdoches Power	NACPW_UNIT1	Nacogdoches	Biomass	North	2012	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0
Skyline Landfill Energy	DG_FERIS_4UNITS	Dallas	Biomass	North	2007	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Trinity Bay	TRN_DG1	Chambers	Biomass	Houston	2002	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Trinity Oaks LFG	DG_KLBRG_1UNIT	Dallas	Biomass	North	2009	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Walzem Road	DG_WALZE_4UNITS	Bexar	Biomass	South	2002	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Westside	DG_WSTHL_3UNITS	Parker	Biomass	North	2010	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Big Brown 1	BBSES_UNIT1	Freestone	Coal	North	1971	606.0	606.0	606.0	606.0	606.0	606.0	606.0	606.0	606.0	606.0
Big Brown 2	BBSES_UNIT2	Freestone	Coal	North	1972	602.0	602.0	602.0	602.0	602.0	602.0	602.0	602.0	602.0	602.0
Coleto Creek	COLETO_COLETOG1	Goliad	Coal	South	1980	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0
Fayette Power Project 1	FPPYD1_FPP_G1	Fayette	Coal	South	1979	603.0	603.0	603.0	603.0	603.0	603.0	603.0	603.0	603.0	603.0
Fayette Power Project 2	FPPYD1_FPP_G2	Fayette	Coal	South	1980	605.0	605.0	605.0	605.0	605.0	605.0	605.0	605.0	605.0	605.0
Fayette Power Project 3	FPPYD2_FPP_G3	Fayette	Coal	South	1988	449.0	449.0	449.0	449.0	449.0	449.0	449.0	449.0	449.0	449.0
Gibbons Creek 1	GIBCRK_GIB_CRG1	Grimes	Coal	North	1982	470.0	470.0	470.0	470.0	470.0	470.0	470.0	470.0	470.0	470.0
J K Spruce 1	CALAVERS_JKS1	Bexar	Coal	South	1992	562.0	562.0	562.0	562.0	562.0	562.0	562.0	562.0	562.0	562.0
J K Spruce 2	CALAVERS_JKS2	Bexar	Coal	South	2010	775.0	775.0	775.0	775.0	775.0	775.0	775.0	775.0	775.0	775.0
J T Deely 1	CALAVERS_JTD1	Bexar	Coal	South	1977	430.0	430.0	430.0	430.0	430.0	430.0	430.0	430.0	430.0	430.0
J T Deely 2	CALAVERS_JTD2	Bexar	Coal	South	1978	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
Limestone 1	LEG_LEG_G1	Limestone	Coal	North	1985	831.0	831.0	831.0	831.0	831.0	831.0	831.0	831.0	831.0	831.0
Limestone 2	LEG_LEG_G2	Limestone	Coal	North	1986	858.0	858.0	858.0	858.0	858.0	858.0	858.0	858.0	858.0	858.0
Martin Lake 1	MLSES_UNIT1	Rusk	Coal	North	1977	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0
Martin Lake 2	MLSES_UNIT2	Rusk	Coal	North	1978	820.0	820.0	820.0	820.0	820.0	820.0	820.0	820.0	820.0	820.0
Martin Lake 3	MLSES_UNIT3	Rusk	Coal	North	1979	820.0	820.0	820.0	820.0	820.0	820.0	820.0	820.0	820.0	820.0
Monticello 1	MNSES_UNIT1	Titus	Coal	North	1974	580.0	580.0	580.0	580.0	580.0	580.0	580.0	580.0	580.0	580.0
Monticello 2	MNSES_UNIT2	Titus	Coal	North	1975	580.0	580.0	580.0	580.0	580.0	580.0	580.0	580.0	580.0	580.0
Monticello 3	MNSES_UNIT3	Titus	Coal	North	1978	795.0	795.0	795.0	795.0	795.0	795.0	795.0	795.0	795.0	795.0
Oak Grove SES Unit 1	OGSES_UNIT1A	Robertson	Coal	North	2011	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0
Oak Grove SES Unit 2	OGSES_UNIT2	Robertson	Coal	North	2011	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0
Oklaunion 1	OKLA_OKLA_G1	Wilbarger	Coal	West	1986	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0
San Miguel 1	SANMIGL_SANMIGG1	Atascosa	Coal	South	1982	391.0	391.0	391.0	391.0	391.0	391.0	391.0	391.0	391.0	391.0
Sandow 5	SD5SES_UNIT5	Milam	Coal	South	2010	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0
Twin Oaks 1	TNP_ONE_TNP_O_1	Robertson	Coal	North	1990	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
Twin Oaks 2	TNP_ONE_TNP_O_2	Robertson	Coal	North	1991	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
W A Parish 5	WAP_WAP_G5	Ft. Bend	Coal	Houston	1977	659.0	659.0	659.0	659.0	659.0	659.0	659.0	659.0	659.0	659.0
W A Parish 6	WAP_WAP_G6	Ft. Bend	Coal	Houston	1978	658.0	658.0	658.0	658.0	658.0	658.0	658.0	658.0	658.0	658.0
W A Parish 7	WAP_WAP_G7	Ft. Bend	Coal	Houston	1980	577.0	577.0	577.0	577.0	577.0	577.0	577.0	577.0	577.0	577.0
W A Parish 8	WAP_WAP_G8	Ft. Bend	Coal	Houston	1982	610.0	610.0	610.0	610.0	610.0	610.0	610.0	610.0	610.0	610.0
A von Rosenberg 1-CT1	BRAUNIG_AVR1_CT1	Bexar	Gas	South	2000	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0
A von Rosenberg 1-CT2	BRAUNIG_AVR1_CT2	Bexar	Gas	South	2000	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0
A von Rosenberg 1-ST1	BRAUNIG_AVR1_ST	Bexar	Gas	South	2000	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Atkins 7	ATKINS_ATKINSG7	Brazos	Gas	North	1973	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
B M Davis 1	B_DAVIS_B_DAVIG1	Nueces	Gas	South	1974	335.0	335.0	335.0	335.0	335.0	335.0	335.0	335.0	335.0	335.0
B M Davis 2	B_DAVIS_B_DAVIG2	Nueces	Gas	South	1976	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
B M Davis 3	B_DAVIS_B_DAVIG3	Nueces	Gas	South	2009	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
B M Davis 4	B_DAVIS_B_DAVIG4	Nueces	Gas	South	2009	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Bastrop Energy Center 1	BASTEN_GTG1100	Bastrop	Gas	South	2002	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0
Bastrop Energy Center 2	BASTEN_GTG2100	Bastrop	Gas	South	2002	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0
Bastrop Energy Center 3	BASTEN_ST0100	Bastrop	Gas	South	2002	234.0	234.0	234.0	234.0	234.0	234.0	234.0	234.0	234.0	234.0
Big Spring	CARBN_BSP_1	Howard	Gas	West	2006	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Bosque County Peaking 1	BOSQUESW_BSQSU_1	Bosque	Gas	North	2000	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
Bosque County Peaking 2	BOSQUESW_BSQSU_2	Bosque	Gas	North	2000	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
Bosque County Peaking 3	BOSQUESW_BSQSU_3	Bosque	Gas	North	2001	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0
Bosque County Peaking 4	BOSQUESW_BSQSU_4	Bosque	Gas	North	2001	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
Bosque County Unit 5	BOSQUESW_BSQSU_5	Bosque	Gas	North	2009	209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0
Brazos Valley 1	BVE_UNIT1	Ft Bend	Gas	Houston	2003	168.0	168.0	168.0	168.0	168.0	168.0	168.0	168.0	168.0	168.0
Brazos Valley 2	BVE_UNIT2	Ft Bend	Gas	Houston	2003	168.0	168.0	168.0	168.0	168.0	168.0	168.0	168.0	168.0	168.0
Brazos Valley 3	BVE_UNIT3	Ft Bend	Gas	Houston	2003	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
Calenergy (Falcon Seaboard) 1	FLCNS_UNIT1	Howard	Gas	West	1987	77.5	77.5	77.5	77.5	77.5	77.5	77.5	77.5	77.5	77.5
Calenergy (Falcon Seaboard) 2	FLCNS_UNIT2	Howard	Gas	West	1987	77.5	77.5	77.5	77.5	77.5	77.5	77.5	77.5	77.5	77.5
Calenergy (Falcon Seaboard) 3	FLCNS_UNIT3	Howard	Gas	West	1988	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
Cedar Bayou 1	CBY_CBY_G1	Chambers	Gas	Houston	1970	745.0	745.0	745.0	745.0	745.0	745.0	745.0	745.0	745.0	745.0
Cedar Bayou 2	CBY_CBY_G2	Chambers	Gas	Houston	1972	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0	749.0
Cedar Bayou 4	CBY4_CT41	Chambers	Gas	Houston	2009	173.0	173.0	173.0	173.0	173.0	173.0	173.0	173.0	173.0	173.0
Cedar Bayou 5	CBY4_CT42	Chambers	Gas	Houston	2009	173.0	173.0	173.0	173.0	173.0	173.0	173.0	173.0	173.0	173.0
Cedar Bayou 6	CBY4_ST04	Chambers	Gas	Houston	2009	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0
Colorado Bend Energy Center	CBEC_GT1	Wharton	Gas	Houston	2007	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0
Colorado Bend Energy Center	CBEC_GT2	Wharton	Gas	Houston	2007	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0
Colorado Bend Energy Center	CBEC_GT3	Wharton	Gas	Houston	2008	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0
Colorado Bend Energy Center	CBEC_GT4	Wharton	Gas	Houston	2008	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0
Colorado Bend Energy Center	CBEC_STG1	Wharton	Gas	Houston	2007	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0
Colorado Bend Energy Center	CBEC_STG2	Wharton	Gas	Houston	2008	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
CVC Channelview 1	CVC_CVC_G1	Harris	Gas	Houston	2008	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
CVC Channelview 2	CVC_CVC_G2	Harris	Gas	Houston	2008	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
CVC Channelview 3	CVC_CVC_G3	Harris	Gas	Houston	2008	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0
CVC Channelview 5	CVC_CVC_G5	Harris	Gas	Houston	2008	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
Dansby 1	DANSBY_DANSBYG1	Brazos	Gas	North	1978	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Dansby 2	DANSBY_DANSBYG2	Brazos	Gas	North	2004	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Dansby 3	DANSBY_DANSBYG3	Brazos	Gas	North	2010	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek 1	DECKER_DPG1	Travis	Gas	South	2000	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
Decker Creek 2	DECKER_DPG2	Travis	Gas	South	2000	428.0	428.0	428.0	428.0	428.0	428.0	428.0	428.0	428.0	428.0
Decker Creek G1	DECKER_DPGT_1	Travis	Gas	South	2000	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Decker Creek G2	DECKER_DPGT_2	Travis	Gas	South	2000	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Decker Creek G3	DECKER_DPGT_3	Travis	Gas	South	2000	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Decker Creek G4	DECKER_DPGT_4	Travis	Gas	South	2000	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
DeCordova A	DCSES_CT10	Hood	Gas	North	2010	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
DeCordova B	DCSES_CT20	Hood	Gas	North	2010	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
DeCordova C	DCSES_CT30	Hood	Gas	North	2010	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0
DeCordova D	DCSES_CT40	Hood	Gas	North	2010	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
Deer Park Energy Center 1	DDPEC_GT1	Harris	Gas	Houston	2002	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Deer Park Energy Center 2	DDPEC_GT2	Harris	Gas	Houston	2002	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0
Deer Park Energy Center 3	DDPEC_GT3	Harris	Gas	Houston	2002	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Deer Park Energy Center 4	DDPEC_GT4	Harris	Gas	Houston	2002	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0	206.0
Deer Park Energy Center S	DDPEC_ST1	Harris	Gas	Houston	2002	290.0	290.0	290.0	290.0	290.0	290.0	290.0	290.0	290.0	290.0
Ennis Power Station 1	ETCCS_UNIT1	Ellis	Gas	North	2002	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0
Ennis Power Station 2	ETCCS_CT1	Ellis	Gas	North	2002	231.0	231.0	231.0	231.0	231.0	231.0	231.0	231.0	231.0	231.0
ExTex La Porte Pwr Stn (AirPro) 1	AZ_AZ_G1	Harris	Gas	Houston	2009	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
ExTex La Porte Pwr Stn (AirPro) 2	AZ_AZ_G2	Harris	Gas	Houston	2009	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
ExTex La Porte Pwr Stn (AirPro) 3	AZ_AZ_G3	Harris	Gas	Houston	2009	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
ExTex La Porte Pwr Stn (AirPro) 4	AZ_AZ_G4	Harris	Gas	Houston	2009	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Forney Energy Center GT11	FRNYPP_GT11	Kaufman	Gas	North	2003	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Forney Energy Center GT12	FRNYPP_GT12	Kaufman	Gas	North	2003	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4
Forney Energy Center GT13	FRNYPP_GT13	Kaufman	Gas	North	2003	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4
Forney Energy Center GT21	FRNYPP_GT21	Kaufman	Gas	North	2003	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4
Forney Energy Center GT22	FRNYPP_GT22	Kaufman	Gas	North	2003	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4
Forney Energy Center GT23	FRNYPP_GT23	Kaufman	Gas	North	2003	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4	178.4
Forney Energy Center STG10	FRNYPP_ST10	Kaufman	Gas	North	2003	404.8	404.8	404.8	404.8	404.8	404.8	404.8	404.8	404.8	404.8
Forney Energy Center STG20	FRNYPP_ST20	Kaufman	Gas	North	2003	404.8	404.8	404.8	404.8	404.8	404.8	404.8	404.8	404.8	404.8
Freestone Energy Center 1	FREC_GT1	Freestone	Gas	North	2002	160.7	160.7	160.7	160.7	160.7	160.7	160.7	160.7	160.7	160.7
Freestone Energy Center 2	FREC_GT2	Freestone	Gas	North	2002	160.7	160.7	160.7	160.7	160.7	160.7	160.7	160.7	160.7	160.7
Freestone Energy Center 3	FREC_ST3	Freestone	Gas	North	2002	179.8	179.8	179.8	179.8	179.8	179.8	179.8	179.8	179.8	179.8
Freestone Energy Center 4	FREC_GT4	Freestone	Gas	North	2002	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1
Freestone Energy Center 5	FREC_GT5	Freestone	Gas	North	2002	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1	161.1
Freestone Energy Center 6	FREC_ST6	Freestone	Gas	North	2002	179.7	179.7	179.7	179.7	179.7	179.7	179.7	179.7	179.7	179.7
Frontera 1	FRONTERA_FRONTEG1	Hidalgo	Gas	South	1999	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Frontera 2	FRONTERA_FRONTEG2	Hidalgo	Gas	South	1999	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Frontera 3	FRONTERA_FRONTEG3	Hidalgo	Gas	South	2000	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0
Graham 1	GRSES_UNIT1	Young	Gas	West	1960	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0
Graham 2	GRSES_UNIT2	Young	Gas	West	1969	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0
Greens Bayou 5	GBY_GBY_5	Harris	Gas	Houston	1973	406.0	406.0	406.0	406.0	406.0	406.0	406.0	406.0	406.0	406.0
Greens Bayou 73	GBY_GBYGT73	Harris	Gas	Houston	1976	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Greens Bayou 74	GBY_GBYGT74	Harris	Gas	Houston	1976	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Greens Bayou 81	GBY_GBYGT81	Harris	Gas	Houston	1976	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Greens Bayou 83	GBY_GBYGT83	Harris	Gas	Houston	1976	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
Greens Bayou 84	GBY_GBYGT84	Harris	Gas	Houston	1976	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
Greenville Engine Plant	STEAM_ENGINE_1	Hunt	Gas	North	2010	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Greenville Engine Plant	STEAM_ENGINE_2	Hunt	Gas	North	2010	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Greenville Engine Plant	STEAM_ENGINE_3	Hunt	Gas	North	2010	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Guadalupe Gen Stn 1	GUADG_GAS1	Guadalupe	Gas	South	2000	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
Guadalupe Gen Stn 2	GUADG_GAS2	Guadalupe	Gas	South	2000	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
Guadalupe Gen Stn 3	GUADG_GAS3	Guadalupe	Gas	South	2000	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0
Guadalupe Gen Stn 4	GUADG_GAS4	Guadalupe	Gas	South	2000	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Guadalupe Gen Stn 5	GUADG_STM5	Guadalupe	Gas	South	2000	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0
Guadalupe Gen Stn 6	GUADG_STM6	Guadalupe	Gas	South	2000	171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0
Handley 3	HLSES_UNIT3	Tarrant	Gas	North	1963	395.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0
Handley 4	HLSES_UNIT4	Tarrant	Gas	North	1976	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0
Handley 5	HLSES_UNIT5	Tarrant	Gas	North	1977	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0
Hays Energy Facility 1	HAYSEN_HAYSENG1	Hays	Gas	South	2002	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0
Hays Energy Facility 2	HAYSEN_HAYSENG2	Hays	Gas	South	2002	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0
Hays Energy Facility 3	HAYSEN_HAYSENG3	Hays	Gas	South	2002	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0
Hays Energy Facility 4	HAYSEN_HAYSENG4	Hays	Gas	South	2002	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0
Hidalgo 1	DUKE_DUKE_GT1	Hidalgo	Gas	South	2000	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Hidalgo 2	DUKE_DUKE_GT2	Hidalgo	Gas	South	2000	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Hidalgo 3	DUKE_DUKE_ST1	Hidalgo	Gas	South	2000	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0
Jack County GenFacility 1	JACKCNTY_CT1	Jack	Gas	North	2005	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Jack County GenFacility 1	JACKCNTY_CT2	Jack	Gas	North	2005	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Jack County GenFacility 1	JACKCNTY_STG	Jack	Gas	North	2005	310.0	310.0	310.0	310.0	310.0	310.0	310.0	310.0	310.0	310.0
Jack County GenFacility 2	JCKCNTY2_CT3	Jack	Gas	North	2011	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Jack County GenFacility 2	JCKCNTY2_CT4	Jack	Gas	North	2011	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Jack County GenFacility 2	JCKCNTY2_ST2	Jack	Gas	North	2011	310.0	310.0	310.0	310.0	310.0	310.0	310.0	310.0	310.0	310.0
Johnson County GenFacility 1	TEN_CT1	Johnson	Gas	North	1997	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0
Johnson County GenFacility 2	TEN_STG	Johnson	Gas	North	1997	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0	106.0
Lake Hubbard 1	LHSES_UNIT1	Dallas	Gas	North	1970	392.0	392.0	392.0	392.0	392.0	392.0	392.0	392.0	392.0	392.0
Lake Hubbard 2	LH2SES_UNIT2	Dallas	Gas	North	2010	515.0	515.0	515.0	515.0	515.0	515.0	515.0	515.0	515.0	515.0
Lamar Power Project CT11	LPCCS_CT11	Lamar	Gas	North	2000	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9
Lamar Power Project CT12	LPCCS_CT12	Lamar	Gas	North	2000	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9
Lamar Power Project CT21	LPCCS_CT21	Lamar	Gas	North	2000	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9
Lamar Power Project CT22	LPCCS_CT22	Lamar	Gas	North	2000	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9	176.9
Lamar Power Project STG1	LPCCS_UNIT1	Lamar	Gas	North	2000	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3
Lamar Power Project STG2	LPCCS_UNIT2	Lamar	Gas	North	2000	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3
Laredo Peaking 4	LARDVFTN_G4	Webb	Gas	South	2008	98.5	98.5	98.5	98.5	98.5	98.5	98.5	98.5	98.5	98.5

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Laredo Peaking 5	LARDVFTN_G5	Webb	Gas	South	2008	98.5	98.5	98.5	98.5	98.5	98.5	98.5	98.5	98.5	98.5
Leon Creek Peaking 1	LEON_CRK_LCPCT1	Bexar	Gas	South	2004	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Leon Creek Peaking 2	LEON_CRK_LCPCT2	Bexar	Gas	South	2004	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Leon Creek Peaking 3	LEON_CRK_LCPCT3	Bexar	Gas	South	2004	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Leon Creek Peaking 4	LEON_CRK_LCPCT4	Bexar	Gas	South	2004	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Lost Pines 1	LOSTPI_LOSTPGT1	Bastrop	Gas	South	2001	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0
Lost Pines 2	LOSTPI_LOSTPGT2	Bastrop	Gas	South	2001	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0
Lost Pines 3	LOSTPI_LOSTPST1	Bastrop	Gas	South	2001	192.0	192.0	192.0	192.0	192.0	192.0	192.0	192.0	192.0	192.0
Magic Valley 1	NEDIN_NEDIN_G1	Hidalgo	Gas	South	2001	218.6	218.6	218.6	218.6	218.6	218.6	218.6	218.6	218.6	218.6
Magic Valley 2	NEDIN_NEDIN_G2	Hidalgo	Gas	South	2001	218.6	218.6	218.6	218.6	218.6	218.6	218.6	218.6	218.6	218.6
Magic Valley 3	NEDIN_NEDIN_G3	Hidalgo	Gas	South	2001	257.9	257.9	257.9	257.9	257.9	257.9	257.9	257.9	257.9	257.9
Midlothian 1	MDANP_CT1	Ellis	Gas	North	2001	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0
Midlothian 2	MDANP_CT2	Ellis	Gas	North	2001	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0
Midlothian 3	MDANP_CT3	Ellis	Gas	North	2001	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0
Midlothian 4	MDANP_CT4	Ellis	Gas	North	2001	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0	237.0
Midlothian 5	MDANP_CT5	Ellis	Gas	North	2002	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0
Midlothian 6	MDANP_CT6	Ellis	Gas	North	2002	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0	247.0
Morgan Creek A	MGSES_CT1	Mitchell	Gas	West	1988	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Morgan Creek B	MGSES_CT2	Mitchell	Gas	West	1988	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Morgan Creek C	MGSES_CT3	Mitchell	Gas	West	1988	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Morgan Creek D	MGSES_CT4	Mitchell	Gas	West	1988	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Morgan Creek E	MGSES_CT5	Mitchell	Gas	West	1988	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Morgan Creek F	MGSES_CT6	Mitchell	Gas	West	1988	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Mountain Creek 6	MCSES_UNIT6	Dallas	Gas	North	1956	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0
Mountain Creek 7	MCSES_UNIT7	Dallas	Gas	North	1958	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
Mountain Creek 8	MCSES_UNIT8	Dallas	Gas	North	1967	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0	568.0
Nueces Bay 7	NUECES_B_NUECESG7	Nueces	Gas	South	1972	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
Nueces Bay 8	NUECES_B_NUECESG8	Nueces	Gas	South	2009	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
Nueces Bay 9	NUECES_B_NUECESG9	Nueces	Gas	South	2009	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
O W Sommers 1	CALAVERS_OWS1	Bexar	Gas	South	1972	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
O W Sommers 2	CALAVERS_OWS2	Bexar	Gas	South	1974	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
Odessa-Ector Gen Stn C11	OECCS_CT11	Ector	Gas	West	2001	162.6	162.6	162.6	162.6	162.6	162.6	162.6	162.6	162.6	162.6
Odessa-Ector Gen Stn C12	OECCS_CT12	Ector	Gas	West	2001	151.2	151.2	151.2	151.2	151.2	151.2	151.2	151.2	151.2	151.2
Odessa-Ector Gen Stn C21	OECCS_CT21	Ector	Gas	West	2001	155.8	155.8	155.8	155.8	155.8	155.8	155.8	155.8	155.8	155.8
Odessa-Ector Gen Stn C22	OECCS_CT22	Ector	Gas	West	2001	153.3	153.3	153.3	153.3	153.3	153.3	153.3	153.3	153.3	153.3
Odessa-Ector Gen Stn ST1	OECCS_UNIT1	Ector	Gas	West	2001	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
Odessa-Ector Gen Stn ST2	OECCS_UNIT2	Ector	Gas	West	2001	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
Paris Energy Center 1	TNSKA_GT1	Lamar	Gas	North	1989	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0
Paris Energy Center 2	TNSKA_GT2	Lamar	Gas	North	1989	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0
Paris Energy Center 3	TNSKA_STG	Lamar	Gas	North	1990	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0
PasGen	PSG_PSG_GT2	Harris	Gas	Houston	2000	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0
PasGen	PSG_PSG_GT3	Harris	Gas	Houston	2000	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0
PasGen	PSG_PSG_ST2	Harris	Gas	Houston	2000	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
Pearsall 1	PEARSALL_PEARS_1	Frio	Gas	South	1961	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall 2	PEARSALL_PEARS_2	Frio	Gas	South	1961	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall 3	PEARSALL_PEARS_3	Frio	Gas	South	1961	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall Engine Plant	PEARSAL2_AGR_A	Frio	Gas	South	2010	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Pearsall Engine Plant	PEARSAL2_AGR_B	Frio	Gas	South	2010	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Pearsall Engine Plant	PEARSAL2_AGR_C	Frio	Gas	South	2010	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Pearsall Engine Plant	PEARSAL2_AGR_D	Frio	Gas	South	2010	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Permian Basin A	PB2SES_CT1	Ward	Gas	West	1988	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
Permian Basin B	PB2SES_CT2	Ward	Gas	West	1988	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
Permian Basin C	PB2SES_CT3	Ward	Gas	West	1988	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
Permian Basin D	PB2SES_CT4	Ward	Gas	West	1990	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Permian Basin E	PB2SES_CT5	Ward	Gas	West	1990	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Powerlane Plant 1	STEAM1A_STEAM_1	Hunt	Gas	North	2009	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Powerlane Plant 2	STEAM_STEAM_2	Hunt	Gas	North	1967	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
Powerlane Plant 3	STEAM_STEAM_3	Hunt	Gas	North	1978	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0
Quail Run Energy GT1	QALSW_GT2	Ector	Gas	West	2007	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0
Quail Run Energy GT2	QALSW_GT3	Ector	Gas	West	2008	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Quail Run Energy GT3	QALSW_STG1	Ector	Gas	West	2007	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Quail Run Energy GT4	QALSW_STG2	Ector	Gas	West	2008	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Quail Run Energy STG1	QALSW_GT1	Ector	Gas	West	2007	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0
Quail Run Energy STG2	QALSW_GT4	Ector	Gas	West	2008	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
R W Miller 1	MIL_MILLERG1	Palo Pinto	Gas	North	2000	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
R W Miller 2	MIL_MILLERG2	Palo Pinto	Gas	North	2000	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
R W Miller 3	MIL_MILLERG3	Palo Pinto	Gas	North	2000	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0
R W Miller 4	MIL_MILLERG4	Palo Pinto	Gas	North	2000	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0
R W Miller 5	MIL_MILLERG5	Palo Pinto	Gas	North	2000	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0
Ray Olinger 1	OLINGR_OLING_1	Collin	Gas	North	1967	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0
Ray Olinger 2	OLINGR_OLING_2	Collin	Gas	North	1971	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0
Ray Olinger 3	OLINGR_OLING_3	Collin	Gas	North	1975	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0
Ray Olinger 4	OLINGR_OLING_4	Collin	Gas	North	2001	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0
Rayburn 1	RAYBURN_RAYBURG1	Victoria	Gas	South	1963	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Rayburn 10	RAYBURN_RAYBURG10	Victoria	Gas	South	2003	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Rayburn 2	RAYBURN_RAYBURG2	Victoria	Gas	South	1963	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Rayburn 7	RAYBURN_RAYBURG7	Victoria	Gas	South	2003	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Rayburn 8	RAYBURN_RAYBURG8	Victoria	Gas	South	2003	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Rayburn 9	RAYBURN_RAYBURG9	Victoria	Gas	South	2003	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Rio Nogales 1	RIONOG_CT1	Guadalupe	Gas	South	2002	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Rio Nogales 2	RIONOG_CT2	Guadalupe	Gas	South	2002	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Rio Nogales 3	RIONOG_CT3	Guadalupe	Gas	South	2002	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Rio Nogales 4	RIONOG_ST1	Guadalupe	Gas	South	2002	323.0	323.0	323.0	323.0	323.0	323.0	323.0	323.0	323.0	323.0
San Jacinto SES 1	SJS_SJS_G1	Harris	Gas	Houston	1995	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
San Jacinto SES 2	SJS_SJS_G2	Harris	Gas	Houston	1995	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Sandhill Energy Center 1	SANDHSYD_SH1	Travis	Gas	South	2001	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Sandhill Energy Center 2	SANDHSYD_SH2	Travis	Gas	South	2001	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Sandhill Energy Center 3	SANDHSYD_SH3	Travis	Gas	South	2001	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Sandhill Energy Center 4	SANDHSYD_SH4	Travis	Gas	South	2001	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Sandhill Energy Center 5A	SANDHSYD_SH_5A	Travis	Gas	South	2004	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Sandhill Energy Center 5C	SANDHSYD_SH_5C	Travis	Gas	South	2004	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
Sandhill Energy Center 6	SANDHSYD_SH6	Travis	Gas	South	2010	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Sandhill Energy Center 7	SANDHSYD_SH7	Travis	Gas	South	2010	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Silas Ray 10	SILASRAY_SILAS_10	Cameron	Gas	South	2004	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Silas Ray 6	SILASRAY_SILAS_6	Cameron	Gas	South	1961	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Silas Ray 9	SILASRAY_SILAS_9	Cameron	Gas	South	1996	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
Sim Gideon 1	GIDEON_GIDEONG1	Bastrop	Gas	South	1965	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Sim Gideon 2	GIDEON_GIDEONG2	Bastrop	Gas	South	1968	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0
Sim Gideon 3	GIDEON_GIDEONG3	Bastrop	Gas	South	1972	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0
Spencer 4	SPNCER_SPNCE_4	Denton	Gas	North	1966	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0
Spencer 5	SPNCER_SPNCE_5	Denton	Gas	North	1973	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0
SR Bertron	SRB_SRB_G1	Harris	Gas	Houston	1958	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
SR Bertron	SRB_SRB_G2	Harris	Gas	Houston	1956	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0
SR Bertron	SRB_SRB_G3	Harris	Gas	Houston	1959	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0
SR Bertron	SRB_SRB_G4	Harris	Gas	Houston	1960	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0
SR Bertron	SRB_SRBGT_2	Harris	Gas	Houston	1967	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Stryker Creek 1	SCSES_UNIT1A	Cherokee	Gas	North	1958	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0	167.0
Stryker Creek 2	SCSES_UNIT2	Cherokee	Gas	North	1965	502.0	502.0	502.0	502.0	502.0	502.0	502.0	502.0	502.0	502.0
Thomas C Ferguson 1	FERGUS_FERGUSG1	Llano	Gas	South	1974	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0
T H Wharton 3	THW_THWST_3	Harris	Gas	Houston	1974	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
T H Wharton 31	THW_THWGT31	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 32	THW_THWGT32	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 33	THW_THWGT33	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 34	THW_THWGT34	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 4	THW_THWST_4	Harris	Gas	Houston	1974	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
T H Wharton 41	THW_THWGT41	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 42	THW_THWGT42	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 43	THW_THWGT43	Harris	Gas	Houston	1974	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 44	THW_THWGT44	Harris	Gas	Houston	1974	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 51	THW_THWGT51	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
T H Wharton 52	THW_THWGT52	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 53	THW_THWGT53	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 54	THW_THWGT54	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 55	THW_THWGT55	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 56	THW_THWGT56	Harris	Gas	Houston	1975	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton G1	THW_THWGT_1	Harris	Gas	Houston	1967	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Texas City 1	TXCTY_CTA	Galveston	Gas	Houston	2000	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4
Texas City 2	TXCTY_CTB	Galveston	Gas	Houston	2000	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4
Texas City 3	TXCTY_CTC	Galveston	Gas	Houston	2000	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4
Texas City 4	TXCTY_ST	Galveston	Gas	Houston	2000	131.5	131.5	131.5	131.5	131.5	131.5	131.5	131.5	131.5	131.5
Texas Gulf Sulphur	TGF_TGFGT_1	Wharton	Gas	Houston	1985	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0
Trinidad 6	TRSES_UNIT6	Henderson	Gas	North	1965	226.0	226.0	226.0	226.0	226.0	226.0	226.0	226.0	226.0	226.0
V H Braunig 1	BRAUNIG_VHB1	Bexar	Gas	South	1966	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
V H Braunig 2	BRAUNIG_VHB2	Bexar	Gas	South	1968	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0
V H Braunig 3	BRAUNIG_VHB3	Bexar	Gas	South	1970	412.0	412.0	412.0	412.0	412.0	412.0	412.0	412.0	412.0	412.0
V H Braunig 5	BRAUNIG_VHB6CT5	Bexar	Gas	South	2009	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
V H Braunig 6	BRAUNIG_VHB6CT6	Bexar	Gas	South	2009	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
V H Braunig 7	BRAUNIG_VHB6CT7	Bexar	Gas	South	2009	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
V H Braunig 8	BRAUNIG_VHB6CT8	Bexar	Gas	South	2009	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
Victoria Power Station 5	VICTORIA_VICTORG5	Victoria	Gas	South	2009	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0
Victoria Power Station 6	VICTORIA_VICTORG6	Victoria	Gas	South	2009	168.0	168.0	168.0	168.0	168.0	168.0	168.0	168.0	168.0	168.0
W A Parish 1	WAP_WAP_G1	Ft. Bend	Gas	Houston	1958	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
W A Parish 2	WAP_WAP_G2	Ft. Bend	Gas	Houston	1958	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
W A Parish 3	WAP_WAP_G3	Ft. Bend	Gas	Houston	1961	258.0	258.0	258.0	258.0	258.0	258.0	258.0	258.0	258.0	258.0
W A Parish 4	WAP_WAP_G4	Ft. Bend	Gas	Houston	1968	552.0	552.0	552.0	552.0	552.0	552.0	552.0	552.0	552.0	552.0
W A Parish T1	WAP_WAPGT_1	Ft. Bend	Gas	Houston	1967	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Wichita Falls 1	WFCOGEN_UNIT1	Wichita	Gas	West	1987	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Wichita Falls 2	WFCOGEN_UNIT2	Wichita	Gas	West	1987	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Wichita Falls 3	WFCOGEN_UNIT3	Wichita	Gas	West	1987	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Wichita Falls 4	WFCOGEN_UNIT4	Wichita	Gas	West	1987	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Winchester Power Park 1	WIPOPA_WPP_G1	Fayette	Gas	South	2010	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Winchester Power Park 2	WIPOPA_WPP_G2	Fayette	Gas	South	2010	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Winchester Power Park 3	WIPOPA_WPP_G3	Fayette	Gas	South	2010	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Winchester Power Park 4	WIPOPA_WPP_G4	Fayette	Gas	South	2010	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Wise-Tractebel Power Proj. 1	WCPP_CT1	Wise	Gas	North	2004	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0
Wise-Tractebel Power Proj. 2	WCPP_CT2	Wise	Gas	North	2004	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0
Wise-Tractebel Power Proj. 3	WCPP_ST1	Wise	Gas	North	2004	290.0	290.0	290.0	290.0	290.0	290.0	290.0	290.0	290.0	290.0
Wolf Hollow Power Proj. 1	WHCCS_CT1	Hood	Gas	North	2002	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0
Wolf Hollow Power Proj. 2	WHCCS_CT2	Hood	Gas	North	2002	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0
Wolf Hollow Power Proj. 3	WHCCS_STG	Hood	Gas	North	2002	293.0	293.0	293.0	293.0	293.0	293.0	293.0	293.0	293.0	293.0
Canyon	CANYHY_CANYHYG1	Comal	Hydro	South	1989	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Eagle Pass Hydro	EAGLE_HY_EAGLE_HY1	Maverick	Hydro	South	1932	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Lakewood Tap	DG_LKWDT_2UNITS	Gonzales	Hydro	South	1931	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Lewisville	DG_LWSVL_1UNIT	Denton	Hydro	North	1991	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
McQueeney	DG_MCQUE_5UNITS	Guadalupe	Hydro	South	1928	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Schumansville	DG_SCHUM_2UNITS	Guadalupe	Hydro	South	1928	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Amistad Hydro 1	AMISTAD_AMISTAG1	Val Verde	Hydro	South	1983	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9
Amistad Hydro 2	AMISTAD_AMISTAG2	Val Verde	Hydro	South	1983	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9
Austin 1	AUSTPL_AUSTING1	Travis	Hydro	South	1940	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Austin 2	AUSTPL_AUSTING2	Travis	Hydro	South	1940	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Buchanan 1	BUCHAN_BUCHANG1	Llano	Hydro	South	1938	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Buchanan 2	BUCHAN_BUCHANG2	Llano	Hydro	South	1938	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Buchanan 3	BUCHAN_BUCHANG3	Llano	Hydro	South	1950	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
Denison Dam 1	DNDAM_DENISOG1	Grayson	Hydro	North	1944	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Denison Dam 2	DNDAM_DENISOG2	Grayson	Hydro	North	1948	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Falcon Hydro 1	FALCON_FALCONG1	Starr	Hydro	South	1954	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Falcon Hydro 2	FALCON_FALCONG2	Starr	Hydro	South	1954	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Falcon Hydro 3	FALCON_FALCONG3	Starr	Hydro	South	1954	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Granite Shoals 1	WIRTZ_WIRTZ_G1	Burnet	Hydro	South	1951	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Granite Shoals 2	WIRTZ_WIRTZ_G2	Burnet	Hydro	South	1951	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Inks 1	INKSDA_INKS_G1	Llano	Hydro	South	1938	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Marble Falls 1	MARBFA_MARBFAG1	Burnet	Hydro	South	1951	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Marble Falls 2	MARBFA_MARBFAG2	Burnet	Hydro	South	1951	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Marshall Ford 1	MARSFO_MARSFOG1	Travis	Hydro	South	1941	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Marshall Ford 2	MARSFO_MARSFOG2	Travis	Hydro	South	1941	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Marshall Ford 3	MARSFO_MARSFOG3	Travis	Hydro	South	1941	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Whitney 2	WND_WHITNEY2	Bosque	Hydro	North	1953	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Comanche Peak 1	CPSES_UNIT1	Somervell	Nuclear	North	1990	1235.0	1235.0	1235.0	1235.0	1235.0	1235.0	1235.0	1235.0	1235.0	1235.0
Comanche Peak 2	CPSES_UNIT2	Somervell	Nuclear	North	1993	1225.0	1225.0	1225.0	1225.0	1225.0	1225.0	1225.0	1225.0	1225.0	1225.0
South Texas 1	STP_STP_G1	Matagorda	Nuclear	South	1988	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0
South Texas 2	STP_STP_G2	Matagorda	Nuclear	South	1989	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0	1375.0
NoTrees Battery	NWF_NBS	Winkler	Storage	West	2012	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
AES Deepwater	APD_APD_PS1	Harris	Storage	Houston	2010	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Kmaybto	DG_KMASB_1UNIT	Wichita	Other	North	2011	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Blue Wing 1	DG_BROOK_1UNIT	Bexar	Solar	South	2010	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Blue Wing 2	DG_ELMEN_1UNIT	Bexar	Solar	South	2010	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Somerset 1	DG_SOME1_1UNIT	Bexar	Solar	South	2012	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Somerset 2	DG_SOME2_1UNIT	Bexar	Solar	South	2012	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Sunedison Rabel Road	DG_VALL1_1UNIT	Bexar	Solar	South	2012	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Sunedison Valley Road	DG_VALL2_1UNIT	Bexar	Solar	South	2012	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Webberville	WEBBER_S_WSP1	Travis	Solar	South	2011	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5
Operational Units Total						**67,225.0**	**67,225.0**	**67,225.0**	**67,225.0**	**67,225.0**	**67,225.0**	**67,225.0**	**67,225.0**	**67,225.0**	**67,225.0**
Generation from Private Use Networks			Gas			**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**	**4,331.0**
RMR Units Total						**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
DC-Ties															
Eagle Pass	DC_S	Maverick	Other	South		36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
East	DC_E	Fannin	Other	North		600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
Laredo VFT	DC_L	Webb	Other	South		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
North	DC_N	Wilbarger	Other	West		220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
Sharyland (Railroad)	DC_R	Hidalgo	Other	South		150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Sharyland (New Railroad Tie)	DC_R2	Hidalgo	Other	South		150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
DC-Ties Total						**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**	**1,256.0**
Switchable Resources															
Kiamichi Energy Facility 1CT101	KMCHI_1CT101	Fannin	Gas	North	2003	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0
Kiamichi Energy Facility 1CT201	KMCHI_1CT201	Fannin	Gas	North	2003	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Kiamichi Energy Facility 1ST	KMCHI_1ST	Fannin	Gas	North	2003	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0
Kiamichi Energy Facility 2CT101	KMCHI_2CT101	Fannin	Gas	North	2003	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0
Kiamichi Energy Facility 2CT201	KMCHI_2CT201	Fannin	Gas	North	2003	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Kiamichi Energy Facility 2ST	KMCHI_2ST	Fannin	Gas	North	2003	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0
Tenaska-Frontier 1	FTR_FTR_G1	Grimes	Gas	North	2000	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Tenaska-Frontier 2	FTR_FTR_G2	Grimes	Gas	North	2000	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Tenaska-Frontier 3	FTR_FTR_G3	Grimes	Gas	North	2000	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Tenaska-Frontier 4	FTR_FTR_G4	Grimes	Gas	North	2000	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0	390.0
Tenaska-Gateway 1	TGCCS_CT1	Rusk	Gas	North	2001	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0
Tenaska-Gateway 2	TGCCS_CT2	Rusk	Gas	North	2001	179.0	179.0	179.0	179.0	179.0	179.0	179.0	179.0	179.0	179.0
Tenaska-Gateway 3	TGCCS_CT3	Rusk	Gas	North	2001	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0
Tenaska-Gateway 4	TGCCS_UNIT4	Rusk	Gas	North	2001	389.0	389.0	389.0	389.0	389.0	389.0	389.0	389.0	389.0	389.0
Switchable Resources Total						**3,168.0**	**3,168.0**	**3,168.0**	**3,168.0**	**3,168.0**	**3,168.0**	**3,168.0**	**3,168.0**	**3,168.0**	**3,168.0**
Wind Resources															
Anacacho Windfarm	ANACACHO_ANA	Kinney	Wind	South	2013	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
Barton Chapel Wind	BRTSW_BCW1	Jack	Wind	North	2007	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Bobcat Wind	BCATWIND_WIND_1	Clay	Wind	North	2013	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0
Buffalo Gap Wind Farm 1	BUFF_GAP_UNIT1	Taylor	Wind	West	2006	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
Buffalo Gap Wind Farm 2	BUFF_GAP_UNIT2_1	Taylor	Wind	West	2007	115.5	115.5	115.5	115.5	115.5	115.5	115.5	115.5	115.5	115.5
Buffalo Gap Wind Farm 2	BUFF_GAP_UNIT2_2	Taylor	Wind	West	2007	117	117	117	117	117	117	117	117	117	117

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Buffalo Gap Wind Farm 3	BUFF_GAP_UNIT3	Taylor	Wind	West	2008	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Bull Creek Wind Plant	BULLCRK_WND1	Borden	Wind	West	2009	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0
Bull Creek Wind Plant	BULLCRK_WND2	Borden	Wind	West	2009	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Callahan Wind	CALLAHAN_WND1	Callahan	Wind	West	2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Camp Springs 1	CSEC_CSECG1	Scurry	Wind	West	2007	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0
Camp Springs 2	CSEC_CSECG2	Scurry	Wind	West	2007	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Capricorn Ridge Wind 1	CAPRIDGE_CR1	Sterling	Wind	West	2007	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0
Capricorn Ridge Wind 2	CAPRIDGE_CR3	Sterling	Wind	West	2008	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0
Capricorn Ridge Wind 3	CAPRIDGE_CR2	Sterling	Wind	West	2007	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Capricorn Ridge Wind 4	CAPRIDG4_CR4	Sterling	Wind	West	2008	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
Cedro Hill Wind	CEDROHIL_CHW1	Webb	Wind	South	2010	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Champion Wind Farm	CHAMPION_UNIT1	Nolan	Wind	West	2008	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0
Delaware Mountain Wind Farm	KUNITZ_WIND_NWP	Culberson	Wind	West	2010	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Desert Sky Wind Farm 1	INDNENR_INDNENR	Pecos	Wind	West	2002	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0
Desert Sky Wind Farm 2	INDNENR_INDNENR_2	Pecos	Wind	West	2002	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
Elbow Creek Wind Project	ELB_ELBCREEK	Howard	Wind	West	2008	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0
Forest Creek Wind Farm	MCDLD_FCW1	Glasscock	Wind	West	2007	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Goat Wind	GOAT_GOATWIND	Sterling	Wind	West	2008	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Goat Wind 2	GOAT_GOATWIN2	Sterling	Wind	West	2010	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Green Mountain Energy 1	BRAZ_WND_WND1	Scurry	Wind	West	2003	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0
Green Mountain Energy 2	BRAZ_WND_WND2	Scurry	Wind	West	2003	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0
Gulf Wind I	TGW_T1	Kenedy	Wind	South	2010	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0
Gulf Wind II	TGW_T2	Kenedy	Wind	South	2010	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0
Hackberry Wind Farm	HWF_HWFG1	Shackelford	Wind	West	2008	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0
Harbor Wind	DG_NUECE_6UNITS	Nueces	Wind	South	2012	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Horse Hollow Wind 1	H_HOLLOW_WND1	Taylor	Wind	West	2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Horse Hollow Wind 1	HHGT_HHOLLOW1	Kendall	Wind	South	2009	213.0	213.0	213.0	213.0	213.0	213.0	213.0	213.0	213.0	213.0
Horse Hollow Wind 2	HHOLLOW2_WIND1	Taylor	Wind	West	2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Horse Hollow Wind 2	HHGT_HHOLLOW2	Kendall	Wind	South	2009	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0
Horse Hollow Wind 3	HHOLLOW3_WND_1	Taylor	Wind	West	2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Horse Hollow Wind 3	HHGT_HHOLLOW3	Kendall	Wind	South	2009	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0
Horse Hollow Wind 4	HHOLLOW4_WND1	Taylor	Wind	West	2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Horse Hollow Wind 4	HHGT_HHOLLOW4	Kendall	Wind	South	2009	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0	115.0
Horse Hollow Wind Callahan	HHGT_CALLAHAN	Kendall	Wind	South	2009	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0
Inadale Wind	INDL_INADALE1	Nolan	Wind	West	2008	197.0	197.0	197.0	197.0	197.0	197.0	197.0	197.0	197.0	197.0
Indian Mesa Wind Farm	INDNNWP_INDNNWP	Pecos	Wind	West	2001	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0
King Mountain NE	KING_NE_KINGNE	Upton	Wind	West	2001	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
King Mountain NW	KING_NW_KINGNW	Upton	Wind	West	2001	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
King Mountain SE	KING_SE_KINGSE	Upton	Wind	West	2001	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
King Mountain SW	KING_SW_KINGSW	Upton	Wind	West	2001	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
Kunitz Wind	KUNITZ_WIND_LGE	Culberson	Wind	West	1995	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Langford Wind Power	LGD_LANGFORD	Tom Green	Wind	West	2009	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
Loraine Windpark I	LONEWOLF_G1	Mitchell	Wind	West	2009	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Loraine Windpark II	LONEWOLF_G2	Mitchell	Wind	West	2009	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Loraine Windpark III	LONEWOLF_G3	Mitchell	Wind	West	2011	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
Loraine Windpark IV	LONEWOLF_G4	Mitchell	Wind	West	2011	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Magic Valley Wind	REDFISH_MV1A	Willacy	Wind	South	2012	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0
Magic Valley Wind	REDFISH_MV1B	Willacy	Wind	South	2012	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0
McAdoo Wind Farm	MWEC_G1	Dickens	Wind	West	2008	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Mesquite Wind	LNCRK_G83	Shackelford	Wind	West	2006	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Notrees-1	NWF_NWF1	Winkler	Wind	West	2009	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0
Ocotillo Wind Farm	OWF_OWF	Howard	Wind	West	2008	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Panther Creek 1	PC_NORTH_PANTHER1	Howard	Wind	West	2008	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0	143.0
Panther Creek 2	PC_SOUTH_PANTHER2	Howard	Wind	West	2008	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0
Panther Creek 3	PC_SOUTH_PANTHER3	Howard	Wind	West	2009	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Papalote Creek Wind	COTTON_PAP2	San Patricio	Wind	South	2010	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Papalote Creek Wind Farm	PAP1_PAP1	San Patricio	Wind	South	2009	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Pecos Wind (Woodward 1)	WOODWRD1_WOODWRD1	Pecos	Wind	West	2001	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0	83.0
Pecos Wind (Woodward 2)	WOODWRD2_WOODWRD2	Pecos	Wind	West	2001	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
Penascal Wind	PENA_UNIT1	Kenedy	Wind	South	2009	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Penascal Wind	PENA_UNIT2	Kenedy	Wind	South	2009	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0	142.0
Penascal Wind	PENA3_UNIT3	Kenedy	Wind	South	2010	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
Post Oak Wind 1	LNCRK2_G871	Shackelford	Wind	West	2007	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Post Oak Wind 2	LNCRK2_G872	Shackelford	Wind	West	2007	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Pyron Wind Farm	PYR_PYRON1	Scurry	Wind	West	2008	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0
Red Canyon	RDCANYON_RDCNY1	Borden	Wind	West	2006	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0
Roscoe Wind Farm	TKWSW1_ROSCOE	Nolan	Wind	West	2008	209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0	209.0
Sand Bluff Wind Farm	MCDLD_SBW1	Glasscock	Wind	West	2008	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Senate Wind Project	SENATEWD_UNIT1	Jack	Wind	West	2013	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Sherbino 2	KEO_SHRBINO2	Pecos	Wind	West	2012	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Sherbino I	KEO_KEO_SM1	Pecos	Wind	West	2008	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Silver Star	FLTCK_SSI	Eastland	Wind	North	2008	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Snyder Wind Farm	ENAS_ENA1	Scurry	Wind	West	2007	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0
South Trent Wind Farm	STWF_T1	Nolan	Wind	West	2008	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
Stanton Wind Energy	SWEC_G1	Martin	Wind	West	2008	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Sweetwater Wind 1	SWEETWND_WND1	Nolan	Wind	West	2003	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Sweetwater Wind 2	SWEETWN2_WND24	Nolan	Wind	West	2006	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Sweetwater Wind 3	SWEETWN2_WND2	Nolan	Wind	West	2004	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Sweetwater Wind 4	SWEETWN3_WND3A	Nolan	Wind	West	2005	29.5	29.5	29.5	29.5	29.5	29.5	29.5	29.5	29.5	29.5
Sweetwater Wind 4	SWEETWN3_WND3B	Nolan	Wind	West	2005	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5
Sweetwater Wind 5	SWEETWN4_WND5	Nolan	Wind	West	2007	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
Sweetwater Wind 6	SWEETWN4_WND4B	Nolan	Wind	West	2007	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
Sweetwater Wind 7	SWEETWN4_WND4A	Nolan	Wind	West	2007	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
Texas Big Spring	SGMTN_SIGNALMT	Howard	Wind	West	1999	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Trent Wind Farm	TRENT_TRENT	Nolan	Wind	West	2001	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0	151.0
Trinity Hills	TRINITY_TH1_BUS1	Young	Wind	North	2012	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
Trinity Hills	TRINITY_TH1_BUS2	Young	Wind	North	2012	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
TSTC West Texas Wind	DG_ROSC2_1UNIT	Nolan	Wind	West	2008	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Turkey Track Wind Energy Center	TTWEC_G1	Nolan	Wind	West	2008	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
West Texas Wind Energy	SW_MESA_SW_MESA	Upton	Wind	West	1999	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
Whirlwind Energy	WEC_WECG1	Floyd	Wind	West	2007	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
Whitetail Wind Energy Project	EXGNWTL_WIND_1	Webb	Wind	South	2013	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0
WKN Mozart	MOZART_WIND_1	Kent	Wind	West	2013	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Wolfe Ridge	WHTTAIL_WR1	Cooke	Wind	North	2008	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
Wind Resources Total						**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**	**10,570**
New Units with Signed IA and Air Permit															
WA Parish Addition	12INR0086	Fort Bend	Gas			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Sandy Creek 1	SCES_UNIT1	McLennan	Coal			925.0	925.0	925.0	925.0	925.0	925.0	925.0	925.0	925.0	925.0
Deepwater Energy Storage	10INR0089	Harris	Storage			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
OCI Alamo 1	13INR0058	Bexar	Solar			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Panda Sherman Power	10INR0021	Grayson	Gas			773.7	773.7	773.7	773.7	773.7	773.7	773.7	773.7	773.7	773.7
Panda Temple Power	10INR0020a	Bell	Gas			770.5	770.5	770.5	770.5	770.5	770.5	770.5	770.5	770.5	770.5
Deer Park Energy Center	14INR0015	Harris	Gas			215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0
Channel Energy Center 138/345kV (	14INR0016	Harris	Gas			190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Ferguson Replacement Project	13INR0021	Llano	Gas			570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0
Antelope Station	13INR0028	Hale	Gas			-	364.0	364.0	364.0	364.0	364.0	364.0	364.0	364.0	364.0
Texas Clean Energy Project	13INR0023	Ector	Coal			-	-	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0
Panda Temple Power	10INR0020b	Bell	Gas			-	-	780.0	780.0	780.0	780.0	780.0	780.0	780.0	780.0
Pondera King Power Project	10INR0022	Harris	Gas			-	-	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0
Total						**3624.2**	**3988.2**	**6388.2**	**6388.2**	**6388.2**	**6388.2**	**6388.2**	**6388.2**	**6388.2**	**6388.2**
New Wind Generation															
Los Vientos	11INR0033	Cameron	Wind			402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0	402.0
Blue Summit Windfarm	12INR0075	Wilbarger	Wind			135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0
Stephens Ranch Wind Energy	12INR0034	Borden	Wind			378.0	378.0	378.0	378.0	378.0	378.0	378.0	378.0	378.0	378.0
Goldthwaite Wind Energy	11INR0013	Mills	Wind			150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Spinning Spur Wind Two	13INR0048	Oldham	Wind			161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0
Mariah Wind	13INR0010b	Parmer	Wind			200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Panhandle Wind	14INR0030a2	Carson	Wind			322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0

Unit Name	Unit Code	County	Fuel	Forecast Zone	Year In Service	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Miami Wind 1 Project	14INR0012	Gray	Wind			401.0	401.0	401.0	401.0	401.0	401.0	401.0	401.0	401.0	401.0
Moore Wind 1	11INR0050	Crosby	Wind			149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0	149.0
Mariah Wind	13INR0010a	Parmer	Wind			200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Midway Farms Wind	11INR0054	San Patricio	Wind			161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0
Longhorn Energy Center	14INR0023	Briscoe	Wind			361.0	361.0	361.0	361.0	361.0	361.0	361.0	361.0	361.0	361.0
Conway Windfarm	13INR0005	Carson	Wind			-	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
South Clay Windfarm	11INR0079a	Clay	Wind			-	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Penascal Wind Farm 3	06INR0022c	Kenedy	Wind			-	202.0	202.0	202.0	202.0	202.0	202.0	202.0	202.0	202.0
Mariah Wind	13INR0010c	Parmer	Wind			-	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Mesquite Creek	09INR0051	Borden	Wind			-	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0	249.0
Gunsight Mountain	08INR0018	Howard	Wind			-	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
New Wind Generation Total						**3,020.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**	**4,591.0**
Switchable Units Unavailable to ERCOT			Gas			**(317.0)**	**(317.0)**	**(317.0)**	**(317.0)**	**(317.0)**	**(317.0)**	**-**	**-**	**-**	**-**
Retiring Units															
J T Deely 1	CALAVERS_JTD1	Bexar	Coal	South	1977	0.00	0.00	0.00	0.00	-425.00	-425.00	-425.00	-425.00	-425.00	-425.00
J T Deely 2	CALAVERS_JTD2	Bexar	Coal	South	1978	0.00	0.00	0.00	0.00	-420.00	-420.00	-420.00	-420.00	-420.00	-420.00
Thomas C Ferguson 1	FERGUS_FERGUSG1	Llano	Gas	South	1974	-425.0	-425.0	-425.0	-425.0	-425.0	-425.0	-425.0	-425.0	-425.0	-425.0
Total Retiring Units						**(425.0)**	**(425.0)**	**(425.0)**	**(425.0)**	**(1,270.0)**	**(1,270.0)**	**(1,270.0)**	**(1,270.0)**	**(1,270.0)**	**(1,270.0)**
Mothballed Resources															
Applied Energy	APD_APD_G1	Harris	Other	Houston	1986	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Atkins	ATKINS_ATKINSG3	Brazos	Gas	North	1954	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Atkins	ATKINS_ATKINSG4	Brazos	Gas	North	1958	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Atkins	ATKINS_ATKINSG5	Brazos	Gas	North	1965	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Atkins	ATKINS_ATKINSG6	Brazos	Gas	North	1969	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Greens Bayou	GBY_GBYGT82	Harris	Gas	Houston	1976	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
North Texas	NTX_NTX_1	Parker	Gas	North	1958	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
North Texas	NTX_NTX_2	Parker	Gas	North	1958	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
North Texas	NTX_NTX_3	Parker	Gas	North	1963	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
Permian Basin Ses	PBSES_UNIT6	Ward	Gas	West	2009	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0
Silas Ray	SILASRAY_SILAS_5	Cameron	Gas	South	1951	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Valley SES	VLSES_UNIT1	Fannin	Gas	North	1962	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0
Valley SES	VLSES_UNIT2	Fannin	Gas	North	1967	520.0	520.0	520.0	520.0	520.0	520.0	520.0	520.0	520.0	520.0
Valley SES	VLSES_UNIT3	Fannin	Gas	North	1971	375.0	375.0	375.0	375.0	375.0	375.0	375.0	375.0	375.0	375.0
Whitney Dam	WND_WHITNEY1	Bosque	Hydro	North	1953	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Mothballed Resources Total						**2,011**	**2,011**	**2,011**	**2,011**	**2,011**	**2,011**	**2,011**	**2,011**	**2,011**	**2,011**
Excluded Resources, per notification from developer															
Cobisa-Greenville	06INR0006	Hunt	Gas						1,792.0	1,792.0	1,792.0	1,792.0	1,792.0	1,792.0	1,792.0

Summer Fuel Types - ERCOT

Fuel type is based on the primary fuel. Capacities of the wind units are included at 8.7%. The amounts available for the grid according to information from the owners of the private network (self-serve) units and the distributed generation units that have registered with ERCOT are included. DC Tie imports are listed as Other and mothballed capacity is excluded.

In MW

Fuel Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Biomass	238	238	238	238	238	238	238	238	238	238
Coal	19,115	19,115	19,355	19,355	19,355	18,510	18,510	18,510	18,510	18,510
Gas	49,337	49,907	51,051	52,431	52,431	52,431	52,431	52,748	52,748	52,748
Nuclear	5,150	5,150	5,150	5,150	5,150	5,150	5,150	5,150	5,150	5,150
Other	628	628	628	628	628	628	628	628	628	628
Hydro	521	521	521	521	521	521	521	521	521	521
Wind	1,107	1,309	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319
Solar	124	124	124	124	124	124	124	124	124	124
Storage	77	77	77	77	77	77	77	77	77	77
Total	76,297	77,069	78,463	79,843	79,843	78,998	78,998	79,315	79,315	79,315

In Percentages

Fuel Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Biomass	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Coal	25.1%	24.8%	24.7%	24.2%	24.2%	23.4%	23.4%	23.3%	23.3%	23.3%
Natural Gas	64.7%	64.8%	65.1%	65.7%	65.7%	66.4%	66.4%	66.5%	66.5%	66.5%
Nuclear	6.7%	6.7%	6.6%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
Other	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
Hydro	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
Wind	1.5%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
Solar	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Storage	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%

Winter Fuel Types - ERCOT

Fuel type is based on the primary fuel. Capacities of the wind units are included at 8.7%. The amounts available for the grid according to information from the owners of the private network (self-serve) units and the distributed generation units that have registered with ERCOT are included. DC Tie imports are listed as Other and mothballed capacity is excluded.

In MW

Fuel Type	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Biomass	238	238	238	238	238	238	238	238	238	238
Coal	19,292	19,292	19,532	19,532	18,687	18,687	18,687	18,687	18,687	18,687
Gas	52,144	52,508	54,668	54,668	54,668	54,668	54,985	54,985	54,985	54,985
Nuclear	5,210	5,210	5,210	5,210	5,210	5,210	5,210	5,210	5,210	5,210
Other	628	628	628	628	628	628	628	628	628	628
Hydro	521	521	521	521	521	521	521	521	521	521
Wind	1,182	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319
Solar	124	124	124	124	124	124	124	124	124	124
Storage	77	77	77	77	77	77	77	77	77	77
Total	79,416	79,917	82,317	82,317	81,472	81,472	81,789	81,789	81,789	81,789

In Percentages

Fuel Type	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Biomass	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Coal	24.3%	24.1%	23.7%	23.7%	22.9%	22.9%	22.8%	22.8%	22.8%	22.8%
Gas	65.7%	65.7%	66.4%	66.4%	67.1%	67.1%	67.2%	67.2%	67.2%	67.2%
Nuclear	6.6%	6.5%	6.3%	6.3%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%
Other	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
Hydro	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Wind	1.5%	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
Solar	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Storage	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%

"Resource Adequacy in ERCOT"

COMMISSIONER KENNETH W. ANDERSON, JR.
PUBLIC UTILITY COMMISSION OF TEXAS

ANALYSIS OF ERCOT'S CAPACITY RESERVE MARGIN
BASED ON ERCOT'S CAPACITY, DEMAND AND RESERVES REPORT, WINTER 2012

Introduction

- Numerous resource adequacy initiatives have been completed since late 2011 to improve price signals and incent new generation.
- Capacity reserve margins can be a target or mandatory.
- ERCOT has historically had a target capacity reserve margin.
- My views regarding certain points that should be considered as the Commission evaluates its options going forward.

Completed Resource Adequacy Initiatives

- Before May 1, 2012 the Commission:
  - Established price floors for certain ancillary services (operating and reliability reserves) that when deployed by ERCOT historically caused incorrect price reversals;
  - Incorporated online non-spin and quick start units into ERCOT's Security Constrained Economic Dispatch (SCED) system so that these services can be dispatched properly;
  - Established a process for the recall of mothballed generation; and
  - Increased responsive reserves by 500 MW (scarcity pricing should begin earlier and last longer).
- Effective Aug. 1, 2012 the Commission:
  - Raised the System-Wide Offer Cap (SWOC) to $4,500.
- On Oct. 26, 2012 the Commission:
  - Raised the SWOC:
    - Beginning June 1, 2013, the SWOC will be $5,000
    - Beginning June 1, 2014, the SWOC will be $7,500
    - Beginning June 1, 2015, the SWOC will be $9,000
  - Re-defined the Peaker Net Margin:
    - $300,000 in 2012 -2013
    - 2014 and forward – three times the Cost of New Entry

Problems with a Mandatory Capacity Reserve Margin

- Currently ERCOT has a 13.75% "*target*" capacity reserve margin.
- Why is the *nature* of ERCOT's capacity reserve margin important?
  - If ERCOT retains a "*target*" capacity reserve margin it is of relatively lower importance because it only is a signal to generation investors of when to build.
    - Note: For reliability purposes, ERCOT procures three types of operating reserves on a daily basis:
      - 2,800 MW of responsive reserves or spinning reserves (up to half can be provided by loads),
      - Between 500 – 1,500 MW of non-spinning reserves (mostly quick start), and
      - Between 250 - 900 MW of regulation-up.
    - In 2012, ERCOT's daily operating reserve procurements represented approximately 4.7%– 6.9% of ERCOT's total installed capacity.
  - If ERCOT adopts a "*mandatory*" minimum capacity reserve margin, it becomes very important because it drives the amount of generation procured either in forward capacity auctions or some other process and translates into dollars imposed on consumers.
- A mandatory capacity reserve margin will result in billions of unnecessary, unavoidable and largely un-hedgeable costs to customers, without guaranteeing rolling blackouts will not occur.

A Mandatory Capacity Reserve Margin Likely Will Lead to Unrealistic Expectations

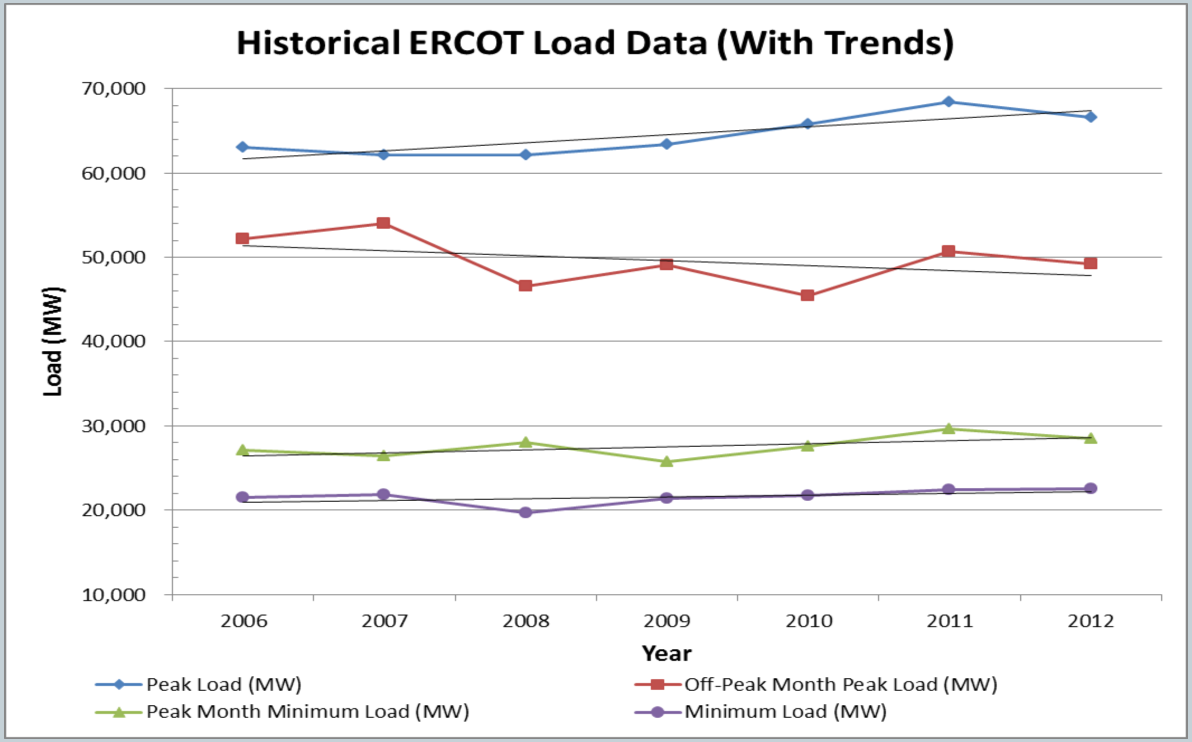
- ERCOT has NEVER experienced a grid collapse, unlike many other parts of the country.
- There have been two ERCOT involuntary rotating load-shed events to avoid grid collapse:
  - April 2006:
    - Had a 16.4% capacity reserve margin;
    - A heat related event;
    - A large number of generation units were down for planned maintenance; and
    - Wind dropped off unexpectedly.
  - Feb. 2011:
    - Had between 15.9% and 17.5% capacity reserve margin;
    - A cold weather event.
- And, in the **winter of 1989**, before ERCOT was the balancing authority, and local vertically integrated electric utilities were their own balancing authority Houston Power and Light had to initiate rolling blackouts to maintain their system because of weather related gas curtailments and generation outages, even though they had a capacity reserve margin of over 30%.
- It is VERY important to remember that normal system planning and the resulting installed capacity reserve margins do not avoid the risk of rolling blackouts from "black swan" events – events that occur outside of the reasonable planning criteria.

ERCOT Has Seen Tight Capacity Reserve Margins Before

- Summer of 1998. Very hot, tight summer. Severe concerns about reserves
- June 2005 Report on Capacity, Demand and Reserves in the ERCOT Region (CDR) showed inadequate reserves by 2010
- June 2006 CDR showed inadequate reserves by 2008
- May 2008 CDR showed inadequate reserves by 2013
- May 2009 and 2010 CDRs showed adequate reserves through at least 2014
- An efficient energy-only market with growing consumption should always show a capacity reserve margin shortfall 4-5 years out.

The REAL Scope of the Problem:
ERCOT *does not* need more Base Load Generation

- ERCOT's high low load trend is relatively flat, so ERCOT has sufficient base load generation.



- ERCOT's Resource Adequacy "problem" actually is only an issue of 160 hours during the summer, out of 8760 total hours per year. (< 2% of the time)
  - 4 hours per day x 5 days per week x 8 weeks per year.
  - And this is probably an inflated number.

Impact of Market Reforms Completed to Date

- Nearly 2,000 MW of mothballed generation voluntarily returned to service for the summer of 2012.

- The ERCOT market met all demand during the summer of 2012 without entering emergency operating conditions.

- 5,031 MW of new generation has been announced, or announced obtaining financing or otherwise moving forward in the trade press.
  - 2,111 MW that is in the Dec. 2012 CDR, and has announced obtaining financing or begun construction,
  - 780 MW that is in the Dec. 2012 CDR, but has not announced obtaining financing and
  - 2,140 MW that is *not* in the Dec. 2012 CDR, but has been announced.

Problems with ERCOT's Capacity Reserve Margin Forecasts

- The Dec 2012 CDR shows ERCOT dropping below its 13.75% target reserve margin in **2013**.
- BUT, the Dec. 2012 CDR projected capacity reserve margins do not include:
  - All mothballed resources that can return to service in < 6 months, nor
  - All reliably anticipated new generation that has announced obtaining financing or otherwise moving forward in the trade press (2,140 MW).
- IMPORTANT: *The load forecast for ERCOT's CDR is highly dependent on economic forecasts. In previous CDRs, this led to a tendency to over forecast in near term years and under forecast in out years. This is important because a forecast that is too high goes right to the bottom line of the capacity reserve margin and impacts all subsequent years.*
- "**Attachment A**" to this presentation is my analysis of ERCOT's December 2012 CDR. My analysis includes:
  - All mothballed generation that can be returned to service in less than 6 months, and
  - All reliably anticipated new generation not included in the Dec. 2012 CDR (2,140 MW), and
  - The incremental wind MWs associated with ERCOT Staff's recommended Effective Load Carrying Capacity (ELCC) of 32.9% and 14.2% for coastal wind and non-coastal wind, respectively, based on ERCOT's 2012 Loss of Load Probability Study. (Incremental from the current 8.7% ELCC for all wind resources).
- CONCLUSION: ERCOT does not dip below its 13.75% target reserve margin until after 2018. (See "Attachment A").

Important Issues

- In a September 27, 2012 memo filed in Docket No. 40000, I addressed resource adequacy steps that I believe need to be taken regardless of major changes to market design:
  - Increase Demand Response:
    - I believe we need a project to consider fully all aspects of the steps necessary to further encourage the development of price responsive loads that operate to assist with price formation, not price suppression.
  - Address Potential Price Reversal Issues Related to the Deployment of Emergency Response Service (ERS) and TDU Load Management Programs:
    - Increasingly important as:
      - ERCOT's programs expand, and
      - If we grant waivers or otherwise encourage TDU Load Programs beyond 2011 levels.
  - Improve the Credit Implications of Clearing and Settlement:
    - Reducing settlement timelines decreases credit and collateral risk for the ERCOT market.
    - I want to see the ERCOT market settle in a time frame that is similar to other financial markets.
  - Implementation of an Integrated Proxy Demand Curve for more efficient integration of operating reserves and Demand Response (DR):
    - More efficient deployment of operating reserves and demand response, without price reversal,
    - Starts with prices above a certain point – say $500, $700, or $1,000 to the SWOC (eliminates price reversal),
    - Can be used in conjunction with the Power Balance Penalty Curve, and
    - Help to smooth out sharp price spikes of short duration (trading height of spikes for duration).

Ongoing Projects

- Project No. 40000 – the Commission's omnibus Resource Adequacy project
  - ERCOT is conducting studies on:
    - Value of Lost Load Study (4-6 months to completion)
    - Loss of Load Probability.
    - Real-Time Market Co-optimization.
    - Appropriate quantity of operating reserves to procure.
    - Appropriate pricing for increased operating reserves.
  - ERCOT is working with IMM and Stakeholders to determine:
    - Market solutions to prevent price reversals due to deployment of existing load resources.
    - Administrative solutions to prevent price reversals due to deployment of existing load resources.
  - ERCOT, Stakeholders, the IMM and Staff are currently working with a nationally known academic to develop an operating reserve demand curve.
- Project No. 41061 – Rulemaking Regarding Demand Response in the ERCOT Market
  - Role of "passive" DR
  - Participation of loads in real-time market
  - Incentives necessary to encourage DR participation
  - Ensure market-based solutions to DR participation that aid in price formation
- Project No. 41060 – Proceeding to Examine the Inputs Included in the ERCOT Capacity, Demand and Reserves Report

Contact Information

Kenneth W. Anderson, Jr.
512-936-7005
kenneth.anderson@puc.state.tx.us

2012 Report on the Capacity, Demand, and Reserves in the ERCOT Region
December Update

Load Forecast:	2013	2014	2015	2016	2017	2018	
Firm Load Forecast, MW	65,952	67,592	69,679	71,613	72,637	73,214	Dec. 10, 2012 CDR
Annual Load Growth	1,334	1,640	2,087	1,934	1,024	577	
Annual % Demand Growth	2.1%	2.5%	3.1%	2.8%	1.4%	0.8%	

		2013	2014	2015	2016	2017	2018	
	Total Existing Resources	74,633	74,943	76,974	77,703	78,742	78,435	
	less Switchable Units Unavailable to ERCOT, MW	0	0	0	0	0	0	Accounted for in Dec. 2012 CDR (-317 MW)
1	Calpine Unit expansions	0	520	520	520	520	520	Public announcement, not in Dec. 2012 CDR
2	CPS solar	25	43	95	148	200	200	Public announcement, not in Dec. 2012 CDR, assumed 50% Effective Load Carrying Capacity (ELCC)
3	Austin Energy Sand Hill Peakers	0	0	0	0	200	200	Referenced in Austin rate review documents posted on City of Austin website, not in Dec. 2012 CDR
4	LCRA Ferguson Plant	0	0	0	0	0	0	Included in Dec. 2012 CDR (116 MW)
5	Summit Power - Net to Grid	0	0	0	0	0	0	Included in Dec. 2012 CDR (240 MW)
6	STEC Peakers	0	0	200	200	200	200	Referenced in Platts and other media, not in Dec. 2012 CDR
7	minus coleto creek	0	0	0	0	0	0	Accounted for in Dec. 2012 CDR (cancelled) (-660 MW)
8	minus las brisas	0	0	0	0	0	0	Accounted for in Dec. 2012 CDR (air permit cancelled) (-1,240 MW)
9	GDF suez uprates	134	134	134	134	134	134	Per recitation in Voluntary Mitigation Plan
10	Sharyland DC Tie expansion	0	0	0	0	0	0	Included in Dec. 2012 CDR (75 MW)
11	NRG Peaker	75	75	75	75	75	75	Public announcement, not in Dec. 2012 CDR (filed IA 12-12-12)
12	actual incremental Load Response seen in 2012	0	0	0	0	0	0	Included in Dec. 2012 CDR (300 MW)
13	additional wind	0	0	0	0	0	0	Included in Dec. 2012 CDR (62 MW)
14	Deeley Retirement by CPS Energy	0	0	0	0	0	0	Accounted for in Dec. 2012 CDR, retiring after 2018 (-845 MW)
15	Frontera TIAC uprate	45	45	45	45	45	45	Public announcement - 10/4/2012
16	NoTrees Battery Storage	0	0	0	0	0	0	Included in Dec. 2012 CDR (36 MW)
17	RRE Solar delay	0	0	0	0	0	0	Accounted for in Dec. 2012 CDR (cancelled) (-60 MW)
18	BPUB Tenaska Plant	0	0	0	800	800	800	Public announcement, not in Dec. 2012 CDR
19	Coastal wind at 32.9% ELCC net add'l MW *	408	496	496	496	496	496	ERCOT Staff's recommended coastal wind ELCC based on ERCOT's 2012 Loss of Load Probability Study.
20	Non-coastal wind at 14.2% ELCC net add'l MW *	512	541	582	602	602	602	ERCOT Staff's recommended non-coastal wind ELCC based on ERCOT's 2012 Loss of Load Probability Study.
	subtotal	1,199	1,853	2,147	3,020	3,272	3,272	
	Total Resources	75,832	76,796	79,121	80,723	82,014	81,707	
	Reserve Margin (December 2012 Report)	13.2%	10.9%	10.5%	8.5%	8.4%	7.1%	
	Reserve Margin (with above new resources)	15.0%	13.6%	13.6%	12.7%	12.9%	11.6%	
	Remaining Mothballed Capacity with return of less than 6 mos	1,720	1,563	1,431	1,754	2,095	2,402	Available mothballed capacity not already included in Dec. 2012 CDR, by year
	Reserve Margin (with above & mothballed with <6 mo return)	17.6%	15.9%	15.6%	15.2%	15.8%	14.9%	

Does not include Sargas Texas 250 MW project announced October 25, 2012 - possible operational date of 2015
Does not include 700 MW La Paloma power plant project in discussion for tax abatements.
Does not include 652 MW of new generation from two compressed air energy storage (CAES) systems that have applied for EPA Green House Gas permits.
Does not include 80 MW 30-Minute ERS Pilot.
* Note: On January 18, 2013, ERCOT staff presented the results of the 2012 Loss of Load Study to the Generation Adequacy Task Force, and recommended a 14.2% ELCC for non-coastal wind resources and a 32.9% ELCC for coastal wind resources.

ATTACHMENT "A"

KWA REVISED PROJECTED DEC. 2012 CDR