Bradley G. Bickett
Reliability Compliance Manager
Henderson Municipal Power & Light (HMP&L)
100 Fifth Street, Henderson, KY 42420
270-826-2726 / Fax 270-826-9650
bbickett@hmpl.net

I have over 12 years of experience in the electric power industry and currently manage electric reliability compliance, transmission and regulatory matters, and wholesale power arrangements.

Professional Experience

November 2010 – Present, Henderson Municipal Power & Light, Henderson, KY.
Reliability Compliance Manager

MISO integration and power supply portfolio development:

- Developed RFP (Request for Proposal) for LBA (Local Balancing Authority) and TOP (Transmission Operator) services to meet requirements of NERC standards as an entity in SERC and in the MISO Balancing Authority Area.
- Manage utility responsibilities under the new LBA and TOP services contract.
- Responsible for HMP&L's forecast of demand and net energy for load as required by MISO and SERC.
- Oversee development of HMP&L's IRP (Integrated Resource Plan).
- Responsible for solicitation of new power supply agreements to replace retiring coal generation units.
- Led activities necessary for utility integration with the MISO (Midcontinent Independent System Operator).
- Secured necessary transmission and resource capacity in MISO.
- Registered utility as a Market Participant and Transmission Owner in MISO and manage obligations for these functions.
- Leading procurement processes to secure future power supply and working on energy/demand conservation measures.
- Work closely with outside legal counsel and secure professional and consulting services as required.

Electric system reliability:

- I developed and manage an internal compliance program for HMP&L that covers all requirements applicable to HMP&L as a Transmission Owner, Distribution Provider, and Load Serving Entity.

July 2009 – October 2010, Big Rivers Electric Corporation, Sebree, KY.
March 2008 - July 2009, Western Kentucky Energy, Sebree, KY
Plant Engineer III

- Implemented procedures and provided necessary documentation for reliability compliance testing; to meet applicable provisions of the NERC standards and to ensure generator reliability.

- Developed plant outage and failure analysis reports.

- Prepared specifications, performed bid evaluations, and managed projects for capital expenditures.
- Supervised 5 electricians and 7 instrumentation technicians as needed.
- Assisted maintenance personnel with troubleshooting issues related to electrical equipment and power distribution systems.
- Worked with transmission and substation personnel for testing and maintenance of oil filled transformers, circuit breakers, and protective relaying equipment.
- Oversaw plant arc flash modeling and reduction of risk to employees by implementation of new technology and procedures.
- Provided technical direction to onsite contractors

January 2003 – March 2008
Electrical Engineer in the automotive manufacturing industry, responsible for equipment specifications and design of control systems.

Education

University of Southern Indiana
Evansville, IN
Anticipated graduation, Dec. 2020
Master of Business Administration

Western Kentucky University
Bowling Green, KY
B.S. degree, Dec. 2002
Electrical Engineering Technology

Activities/Certifications

Member of IEEE (The Institute of Electrical and Electronics Engineers)
Henderson Leadership Initiative, 2014

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

October 25, 2018

Mr. Chris Heimgartner
General Manager
Henderson Municipal Power & Light
P.O. Box 8
Henderson, KY 42419

VIA HAND-DELIVERY AND CERTIFIED MAIL

Re: Notice of Termination of Agreement for Assignment of Responsibility for Complying with Reliability Standards Between Henderson Municipal Power & Light and Big Rivers Electric Corporation, dated July 16, 2009, as amended

Dear Chris,

As you know, on July 27, 2018, Big Rivers Electric Corporation ("Big Rivers") and Henderson Municipal Power and Light ("HMPL") submitted a completed Attachment Y Notice to MISO for Retirement of HMPL Units 1 and 2 effective February 1, 2019. Because HMPL directed Big Rivers not to exercise its right to rescind the Attachment Y submission in the allotted time period, on October 8, 2018, MISO determined that the decision to retire HMPL Units 1 and 2 was final, and as such, determined that the existing interconnection rights for the generators shall terminate as of February 1, 2019. Because the Station Two contracts have terminated and the interconnection rights for the HMPL units will be terminated as of February 1, 2019, Big Rivers is hereby providing HMPL with notice of its intent to terminate the Agreement for Assignment of Responsibility for Complying with Reliability Standards between Henderson Municipal Power & Light and Big Rivers Electric Corporation pursuant to Section 2.3, Termination, of said Agreement. This termination will be effective February 1, 2019.

As a result of the terminations of the Station Two Contracts and the aforementioned agreement (along with the fact that MISO has determined through the Attachment Y process that the Station Two units will be retired as of February 1, 2019), Big Rivers will have no further contractual obligation and will cease providing Local Balancing Authority (LBA), Market Participant (MP) or Meter Data Management Agent (MDMA) services to HMPL as of that date.

As we discussed during our meeting on Friday, October 19, 2018 in your offices, as of February 1, 2019, HMPL will be directly responsible for purchasing energy and capacity to cover HMPL's load. We also discussed the need for HMPL to take the necessary steps prior to February 1, 2019 which will allow HMPL to participate in the MISO market independently

Exhibit Bickett-2

from Big Rivers, including but not limited to determining who will act as HMPL's Market Participant/Billing Agent within MISO as well as who will serve as HMPL's LBA and MDMA after Big Rivers ceases to perform these functions. In addition, HMPL will need to submit a Transmission Service Request for Network Integrated Transmission Service (TSR for NITS). It is my understanding from our meeting that HMPL is aware of the steps it needs to take and has been working directly with MISO to accomplish the necessary steps in order to participate in the MISO market by February 1, 2019. To this end, Big Rivers personnel have been working directly with Brad Bickett on these issues, and will continue to cooperate with HMPL during this process as needed.

Following February 1, 2019, Big Rivers will continue to provide to MISO both real-time and after-the-fact tie line data between Big Rivers and HMPL. That power flow will be reported to MISO via ICCP data and checked out with MISO at the end of each day. Should HMPL fail to make arrangements for LBA services, MP service, and MDMA service, MISO will have the ability and authority to charge HMPL for services it is taking from MISO.

Please let me know if this letter generates any questions or if you need anything further from Big Rivers.

Respectfully,

Robert W. Berry

Robert W. Berry
President and CEO
Big Rivers Electric Corporation

cc: MISO, Carmen Clark

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BALANCING AND FREQUENCY CONTROL

A Technical Document Prepared by the NERC Resources Subcommittee

to ensure the reliability of the bulk power system

January 26, 2011

116-390 Village Blvd., Princeton, NJ 08540
609.452.8060 | 609.452.9550 fax
www.nerc.com

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Introduction

Background

The NERC Resources Subcommittee drafted this reference at the request of the NERC Operating Committee as part of a series on Operating and Planning Reliability Concepts. The document covers balancing and frequency control concepts, issues, and recommendations. Send questions and suggestions for changes and additions to balancing@nerc.com.

Note to Trainers

Trainers are encouraged to develop and share materials based on this reference. The NERC Resources Subcommittee will post supporting information at: http://www.nerc.com/~filez/rs_tutorials.html.

Disclaimer

This document is intended to explain the concepts and issues of balancing and frequency control. The goal is to provide a better understanding of the fundamentals. Nothing in this document is intended to be used for compliance purposes or establish obligations.

Balancing Fundamentals

Balancing and Frequency Control Basics

The power system of North America is divided into four major Interconnections. These Interconnections can be thought of as (frequency-) independent islands. The Interconnections are:

- Western – Generally everything west of the Rockies.
- Texas – Also known as Electric Reliability Council of Texas (ERCOT).
- Eastern – Generally everything east of the Rockies except Texas and Quebec.
- Quebec

Each Interconnection is actually a large machine, as every generator within the island is pulling in tandem with the others to supply electricity to all customers. This occurs as the rotation of electric generating units, nearly all in (steady-state) synchronism. The "speed" (of rotation) of the Interconnection is frequency, measured in cycles per second or Hertz (Hz). If the total Interconnection generation exceeds customer demand, frequency increases beyond the target value, typically 60 Hz[1], until energy balance is achieved. Conversely, if there is a temporary generation deficiency, frequency declines until balance is again restored at a point below the scheduled frequency. Balance is initially restored in each case due to load that varies with frequency and generator governors that change generator output in response to frequency changes. Some electric devices, such as electric motors, use more energy if driven at a higher frequency and less at a lower frequency.

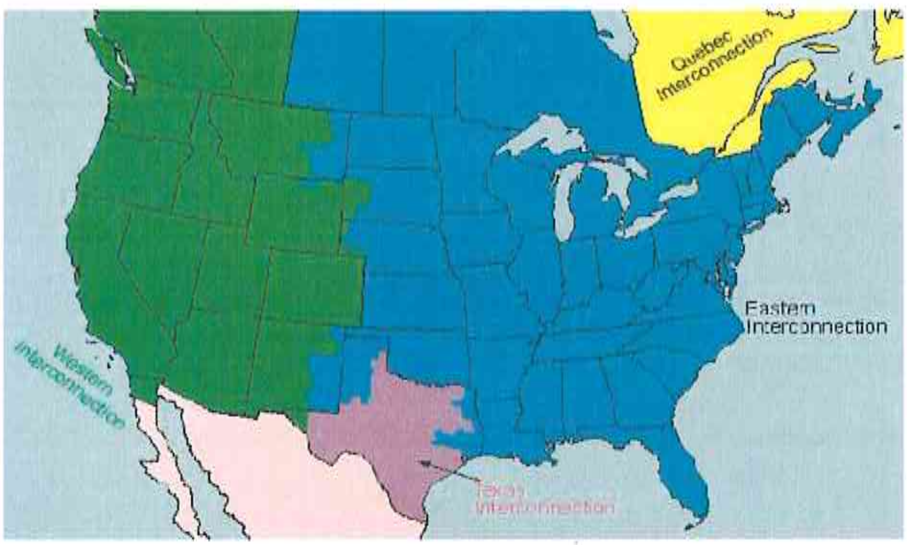


Figure 1 — North American Interconnections

1 Target frequency (termed Scheduled Frequency) is sometimes offset by a small amount via a mechanism called Time Error Corrections. In the Easternn Interconnection this is presently +/- 0.02Hz

Balancing of generation and load within the Interconnections is handled by entities called Balancing Authorities. The Balancing Authorities dispatch generators in order to meet their individual needs. Some Balancing Authorities also control load to maintain the load – generation balance.

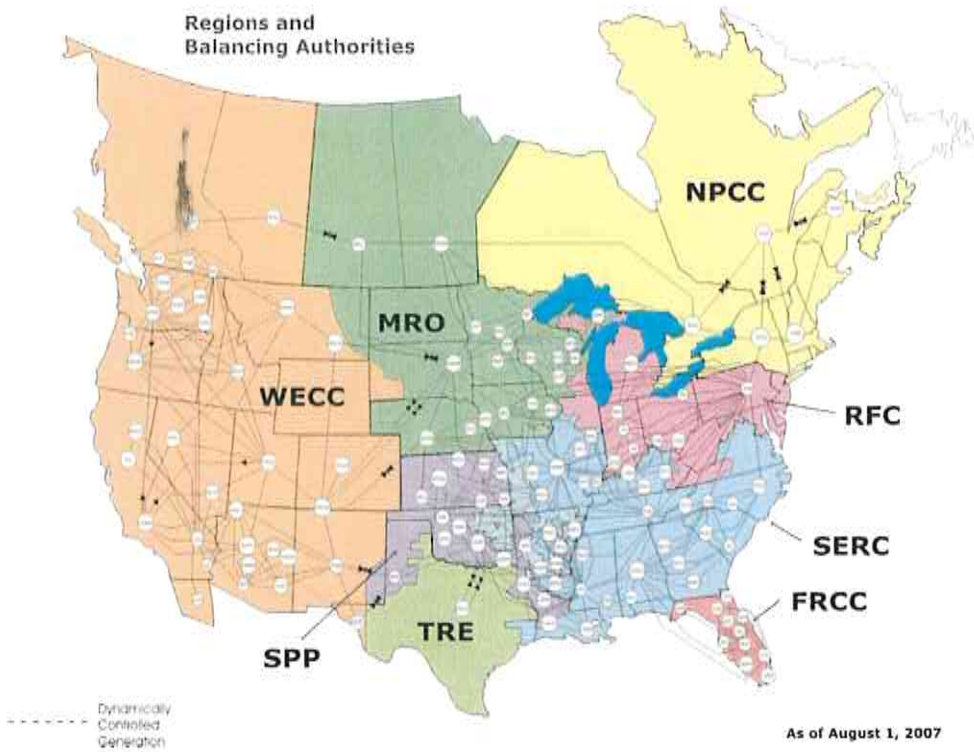


Figure 2 —North American Balancing Authorities and Regions

There are over 100 Balancing Authorities of varying size in North America. Each Balancing Authority in an Interconnection is connected via high voltage transmission lines (called tie-lines) to neighboring Balancing Authorities. Overseeing the Balancing Authorities are wide-area operators called Reliability Coordinators. The relationship between Reliability Coordinators and Balancing Authorities is similar to that between air traffic controllers and pilots.

Frequency does not change in an Interconnection as long as there is a balance between resources and customer demand (including various electrical losses). This balance is depicted in Figure 3a.

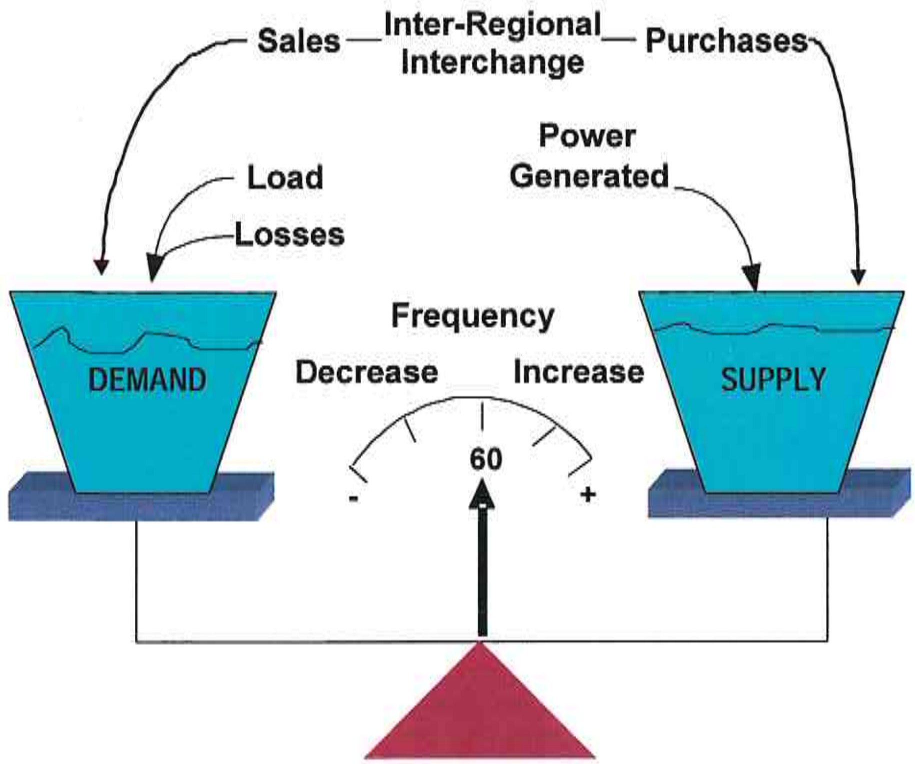


Figure 3a — Generation / Demand Balance

Each generator embedded in an interconnected system has its own characteristics, which can be analogized to a pump with storage and control, as shown in Figure 3b. Here, the pump's output fills a storage tank (similar to a steam drum in a thermal-steam unit). The control valve acts like an AGC input, changing average output to meet system demand. The surge tank on the final output is analogous to the rotational inertia of the generator.

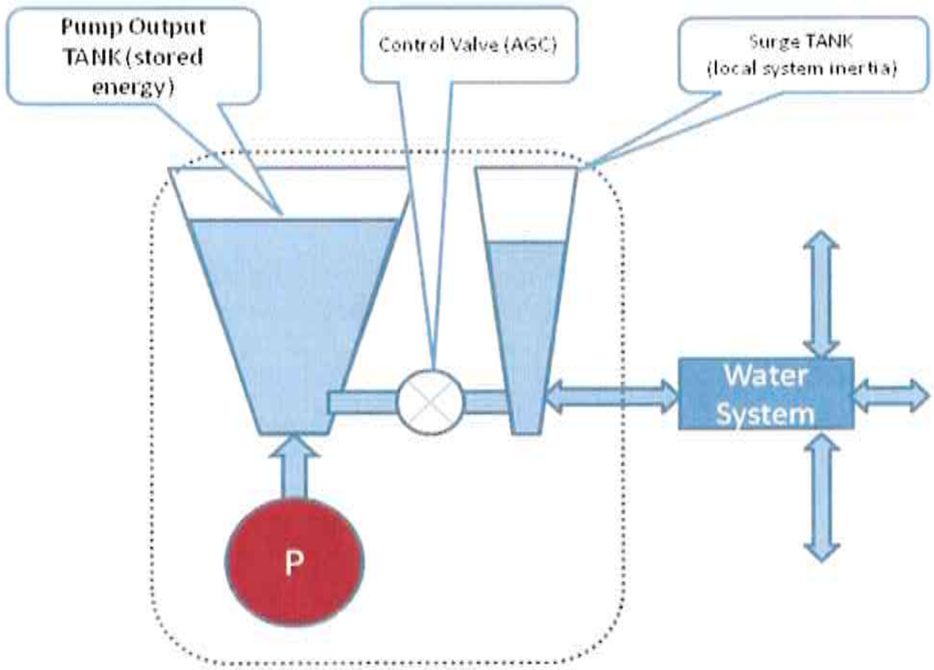


Figure 3b — Generator / Pump Analogy

To understand how Interconnection frequency is actually controlled, it may help to visualize a traditional water utility, composed of a delivery system, customers, and several pumps as depicted above. If a municipality operated its own system, it would need sufficient pumps (generation) to maintain level in a storage tank (frequency) to serve its customers. If demand exceeded supply, the level would drop. Level (frequency) is the primary parameter to control in an independent system.

Utilities quickly learned the benefits in reliability and reduced operating reserves expense by connecting to neighboring systems. In our water utility example, an independent utility must have pumps in standby equivalent to its largest online pump if it wants to maintain level. However, if utilities are connected together via pipelines (tie-lines), reliability and economics are improved, both because of the larger storage capability of the combined system and the ability to share pump capacity when needed.

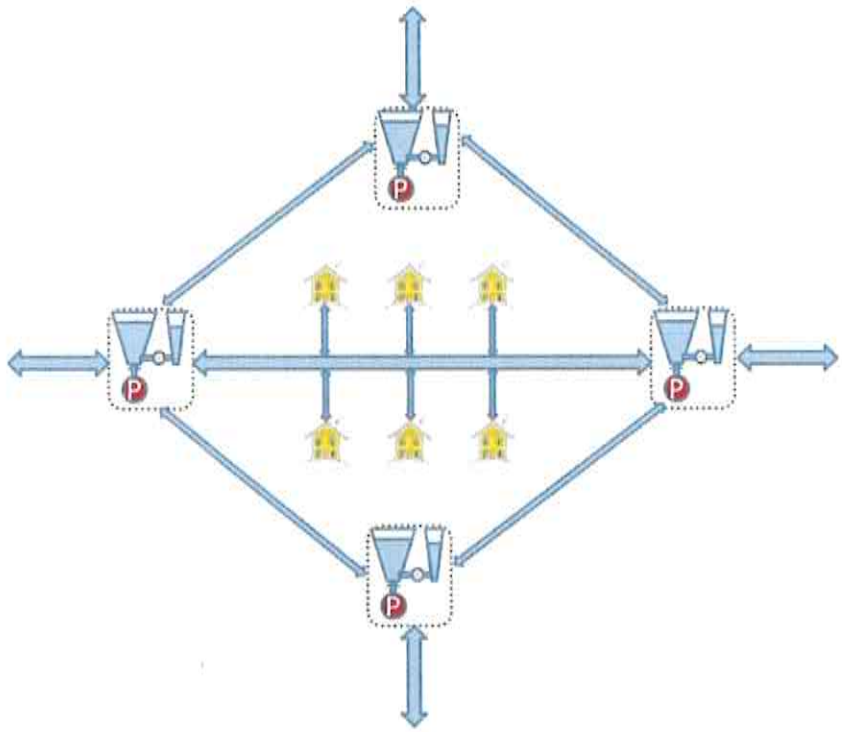


Figure 3 — Balancing Authority Analogy

Once the systems are interconnected, the level (steady state frequency) is the same throughout. If one utility (Balancing Authority) loses a pump, there is a drop in level, although it is now much less than in an independent system. The Balancing Authority that needed water (energy) could purchase output from others.

Thus, there are two inputs to the Balancing Authorities' control process[2]:

- Interchange Error, which is the net outflow or inflow compared to what it is scheduled to be buying or selling.
- Frequency Bias, which is the Balancing Authority's obligation to provide or absorb energy to assist in stabilizing frequency. In other words, if frequency goes low, each Balancing Authority is asked to contribute a small amount of extra generation in proportion to its system's established bias.

Each Balancing Authority uses common meters on the tie-lines with its neighbors for control and accounting. In other words, there will be a meter on one end of each tie-line that both neighboring Balancing Authorities use against which they control and perform accounting. Thus, all generators, load, and transmission lines in an Interconnection fall within the metered bounds of a Balancing Authority.

2 There are two control inputs in multi-Balancing Authority Interconnections. Texas and Quebec are single Balancing Authority Interconnections and need only control to frequency.

Exhibit Bickett-3

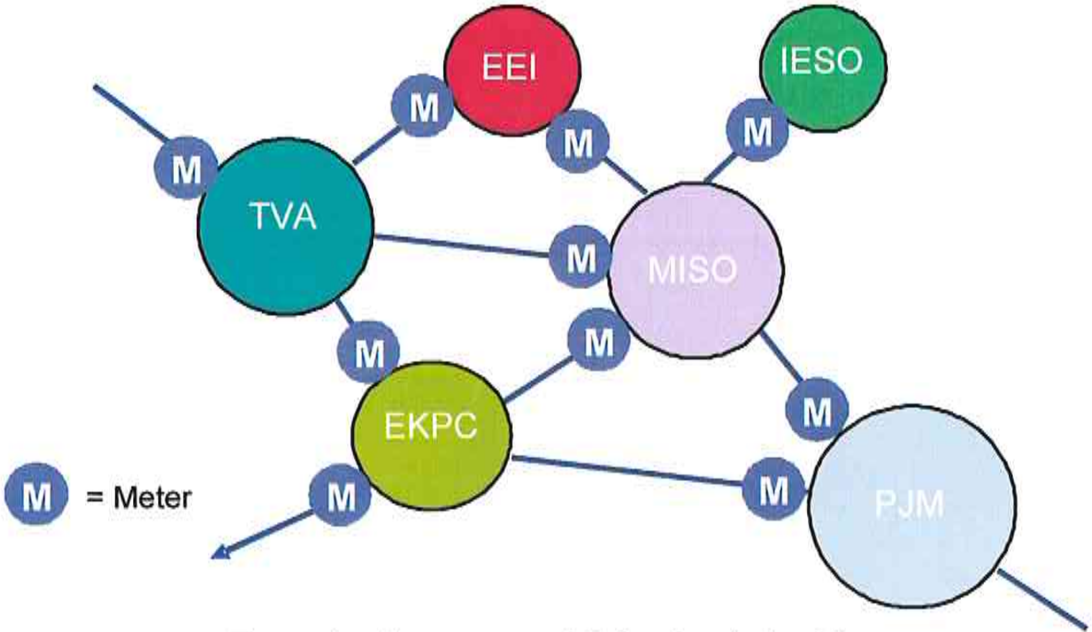


Figure 4 — Interconnected Balancing Authorities

If the Balancing Authority is not buying or selling energy[3], and its generation is exactly equal to the load and losses within its metered boundary, and interconnection frequency is exactly on schedule then the net of its tie line meters will be zero. If the Balancing Authority chooses to buy energy, say 100 Megawatts (MW), it tells its control system to allow 100 MW to flow in. Conversely, the seller will tell its control system to allow 100 MW to flow out. If all Balancing Authorities behave this way, the Interconnection remains in balance and frequency remains stable. If an error in control (and a resulting imbalance) occurs, it will show up as a change in frequency.

Customer demand and generation are constantly changing within all Balancing Authorities. This means Balancing Authorities will usually have some unintentional outflow or inflow at any given instant. This mismatch in meeting a Balancing Authority's internal obligations, along with the small additional "bias" obligation to maintain frequency, is represented via a real-time value called area control error (ACE), estimated in MW.

Dispatchers at each Balancing Authority fulfill their NERC obligations by monitoring ACE and keeping the value within limits that are generally proportional to Balancing Authority size. This balancing typically is accomplished through a combination of computer-controlled adjustment of generators, telephone calls to power plants and

3 In most cases, Balancing Authorities do not buy and sell energy. Transactions now are arranged by agents called Purchasing-Selling Entities (PSEs) that represent load or generation within the Balancing Authority.

through purchases and sales of electricity with other Balancing Authorities, and possible emergency actions such as automatic or manual load shedding.

Conceptually, ACE is to a Balancing Authority what frequency is to the Interconnection. Over-generation makes ACE go positive and puts upward pressure on Interconnection frequency. A large negative ACE causes Interconnection frequency to drop. Highly variable, or "noisy", ACE tends to contribute to similarly "noisy" frequency. However, the effect of ACE on frequency depends on whether ACE is coincident with frequency error. Frequency error tends to be made larger when ACE is of the same sign as the error, and is made smaller when ACE is of opposite sign to the frequency error. This principle is captured in the way CPS1 measures performance.

Failure to maintain a balance between load and resources causes frequency to vary from its target value. Other problems on the grid, such as congestion or equipment faults which dictate rapid unilateral adjustments of generation or loss of load cause changes in frequency. Frequency can therefore be thought of as the pulse of the grid and a fundamental indicator of the health of the power system.

Control Continuum

Balancing and frequency control occur over a continuum of time using different resources, represented in
Figure 5.

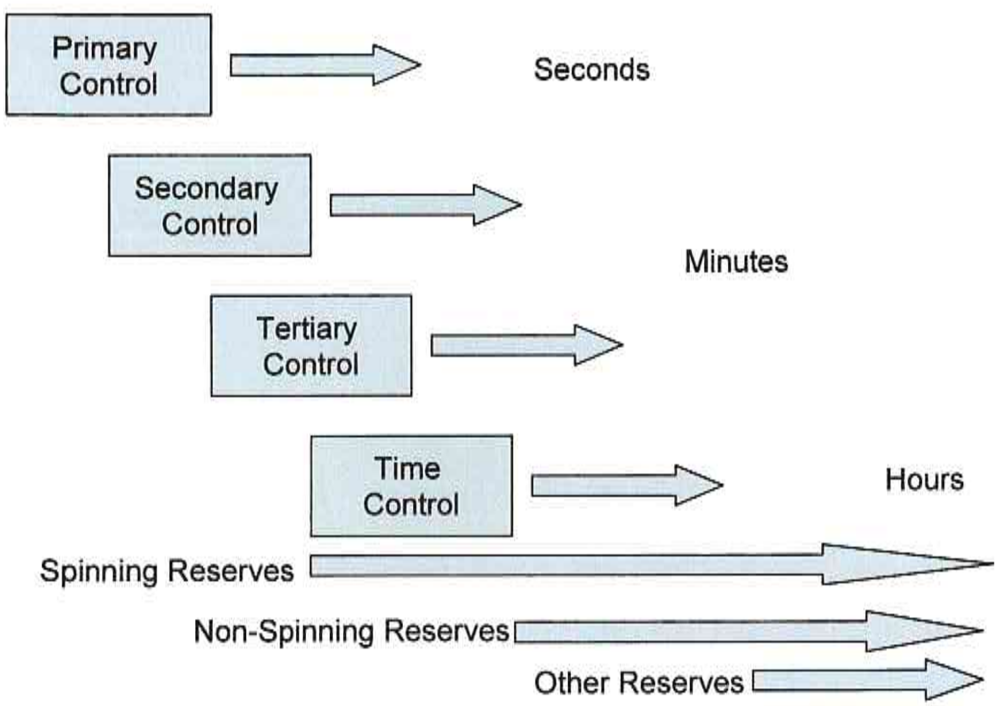


Figure 5 — Control Continuum

Primary Control
Primary Control is more commonly known as Frequency Response. Frequency Response occurs within the first few seconds following a change in system frequency (disturbance) to stabilize the Interconnection. Frequency Response is provided by:

1. Governor Action. Governors on generators are similar to cruise control on your car. They sense a change in speed and adjust the energy input into the generators' prime mover.
2. Load. The speed of motors in an Interconnection change in direct proportion to frequency. As frequency drops, motors will turn slower and draw less energy. Rapid reduction of system load may also be effected by automatic operation of under-frequency relays which interrupt pre-defined loads within fractions of seconds or within seconds of frequency reaching a predetermined value. Such reduction of load may be contractually represented as interruptible load or may be provided in the form of resources procured as reliability (or Ancillary) services. As a safety net, percentages of firm load may be dropped by under-frequency load shedding programs to ensure stabilization of the systems under severe disturbance scenarios.

   These load characteristics assist in stabilizing frequency following a disturbance.

The most common type of disturbance in an Interconnection is associated with the loss of a generator, which causes a decline in frequency. In general, the amount of (frequency-responsive) Spinning Reserve in an Interconnection will determine the amount of available Frequency Response.

It is important to remember that Primary Control will not return frequency to normal, but only stabilize it. Other control components are used to restore frequency to normal.

> **Operating Tip:** Frequency Response is particularly important during disturbances and islanding situations. Operators should be aware of their frequency responsive resources. Blackstart units must be able to control to frequency and arrest excursions.

Secondary Control
Secondary Control typically includes the balancing services deployed in the "minutes" time frame. Some resources however, such as hydroelectric generation, can respond faster in many cases. This control is accomplished using the Balancing Authority's control computer[4] and the manual actions taken by the dispatcher to provide additional adjustments. Secondary Control also includes initial reserve deployment for disturbances.

In short, Secondary Control maintains the minute-to-minute balance throughout the day and is used to restore frequency to its scheduled value, usually 60 Hz, following a

4 Terms most often associated with this are "Load-Frequency Control" or "Automatic Generation Control".

disturbance. Secondary Control is provided by both Spinning and Non-Spinning Reserves.

The most common means of exercising secondary control is through Automatic Generation Control (AGC). AGC operates in conjunction with Supervisory Control and Data Acquisition (SCADA) systems. SCADA gathers information about an electric system, in particular system frequency, generator outputs, and actual interchange between the system and adjacent systems. Using system frequency and net actual interchange, plus knowledge of net scheduled interchange, it is possible to determine the system's energy balance with its interconnection in near-real-time. Most SCADA systems poll sequentially for electric system data, with a typical periodicity of four seconds. Because of this, data is naturally slightly out of perfect time sync, but is of sufficient quality to permit balancing and good frequency control.

AGC computes a Balancing Area's Area Control Error (ACE, further described below) from interchange and frequency data. ACE tells whether a system is in balance or needs to make adjustments to generation. AGC software, while observing ACE, automatically determines the most economical output for generating resources while observing energy balance and frequency control, usually by sending setpoints to generators. Some generators also use pulse-accumulator methodology to derive a setpoint from pulses sent by AGC, but these have become less common over time.

The degree of success of AGC in complying with balancing and frequency control is manifested in a Balancing Area's control performance compliance statistics, which are described in greater detail later in this document.

Tertiary Control
Tertiary Control encompasses actions taken to get resources in place to handle current and future contingencies. Reserve deployment and Reserve restoration following a disturbance are common types of Tertiary Control.

Time Control
Frequency and balancing control are not perfect. There will always be occasional errors in tie-line meters, whether due to transducer inaccuracy, problems with SCADA hardware or software, or communications errors. Due to these errors, plus normal load and generation variation, net ACE in an Interconnection cannot be maintained at zero. This means that frequency cannot always be maintained at exactly 60Hz, and that average frequency over time usually is not exactly 60 Hz.

Each Interconnection has a Time Control process to maintain the long-term average frequency at 60 Hz. While there are some differences in process, each Interconnection designates a Reliability Coordinator as a "Time Monitor" to provide Time Control.

The Time Monitor compares a clock driven off Interconnection frequency against "official time" provided by the National Institute of Standards and Technology (NIST). If average frequency drifts, it creates a Time Error between these two clocks. In the

Western Interconnection, time-error-correction is done automatically through software maintained by the Time Monitor known as Automatic Time Error Correction. In the other interconnections, if the Time Error gets too large, the Time Monitor will notify Balancing Authorities in the Interconnection to correct the situation.

For example, if frequency has been running 2 mHz high (60.002Hz), a clock using Interconnection frequency as a reference will gain 1.2 seconds in a 10 hour interval (i.e., 60.002 Hz-60.000 Hz)/60 Hz * 10 hrs * 3600 s/hr = 1.2 s). If the Time Error accumulates to a pre-determined value (for this example, +10 seconds in the Eastern Interconnection), the Time Monitor will send notices for all Balancing Authorities in the Interconnection to offset their scheduled frequency by -0.02Hz (Scheduled Frequency = 59.98Hz). This offset, known as Time Error Correction, will be maintained until Time Error has decreased below the termination threshold (which would be +6 seconds for our example in the eastern interconnection).

A positive offset (Scheduled Frequency = 60.02Hz) would be used if average frequency was low and Time Error reached its initiation value (-10 seconds for the Eastern Interconnection). See the NAESB business practice on Manual Time Error Correction for additional information.

Control Continuum
Summary Table 1 summarizes the discussion on the control continuum and identifies the service[5] that provides the control and the NERC standard that addresses the adequacy of the service.

Control	Ancillary Service/IOS	Timeframe	NERC Standard
Primary Control	Frequency Response	10-60 Seconds	FRS-CPS1
Secondary Control	Regulation	1-10 Minutes	CPS1– CPS2 – DCS - BAAL
Tertiary Control	Imbalance/Reserves	10 Minutes - Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	TEC

Table 1 — Control Continuum Summary

Current issues, good practices, and recommendations on balancing and frequency control are discussed later.

5 NERC calls these services "Interconnected Operations Services" while the FERC uses the term Ancillary Services.

Area Control Error (ACE) Review

The Control Performance Standards are based on measures that limit the magnitude and direction of the Balancing Authority's Area Control Error (ACE). The equation for ACE is:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Where:

NI_A is Net Interchange, Actual
NI_S is Net Interchange, Scheduled
B is Balancing Authority Bias
F_A is Frequency, Actual
F_S is Frequency, Scheduled
I_{ME} is Interchange (tie line) Metering Error

NI_A is the algebraic sum of tie line flows between the Balancing Authority and the Interconnection. NI_S is the net of all scheduled transactions with other Balancing Authorities. In most areas, flow into a Balancing Authority is defined as negative. Flow out is positive.

The combination of the two (NI_A - NI_S) represents the ACE associated with meeting schedules, without consideration for frequency error or bias, and if used by itself for control would be referred to as "flat tie line" control.

The term 10B (F_A - F_S) is the Balancing Authority's obligation to support frequency. B is the Balancing Authority's frequency bias stated in MW/0.1Hz (B's sign is negative). The "10" converts the Bias setting to MW/Hz. F_S is normally 60 Hz but may be offset ± 0.02 Hz for time error corrections. Control using "10B (F_A - F_S)" by itself is called "flat frequency" control.

I_{ME} is a correction factor for meter error. The meters that measure instantaneous[6] flow are not always as accurate as the hourly meters on tie lines. Balancing Authorities are expected to check the error between the integrated instantaneous and the hourly meter readings. If there is a metering error, a value should be added to compensate for the estimated error. This value is I_{ME}. This term should normally be very small or zero.

Here is a simple example. Assume a Balancing Authority with a Bias of -50 MW / 0.1 Hz is purchasing 300 MW. The actual flow into the Balancing Authority is 310 MW. Frequency is 60.01 Hz. Assume no time correction or metering error.

ACE = (-310 - - 300) – 10* (-50) * (60.01 – 60.00) = (-10) – (-5) = -5 MW.

6 Instantaneous, as used herein, refers to measurements which are as close to real-time, or instantaneous, as are possible within the limits of data acquistion and conversion equipment.

The Balancing Authority should be generating 5 MW more to meet its obligation to the Interconnection. Even though it may appear counterintuitive to increase generation when frequency is high, the reason is that this Balancing Area is more energy-deficient at this moment (-10 MW) than its bias obligation to reduce frequency (-5 MW). The decision on when or if to correct the -5 MW ACE would be driven by control performance standard (CPS) compliance.

Bias (B) vs. Frequency Response (Beta)

There is often confusion in the Industry when discussing Frequency Bias and Frequency Response. Even though there are similarities between the two terms, Frequency Bias (B) is not the same as Frequency Response (β).

Frequency Response, defined in the NERC Glossary[7], is the mathematical expression of the net change in a Balancing Area's Net Actual Interchange for a change in interconnection frequency. It is a fundamental reliability service provided by a combination of governor and load response. Frequency Response represents the actual MW primary response contribution to stabilize frequency following a disturbance.

Bias is an approximation of β used in the ACE equation. Bias prevents AGC withdrawal of frequency support following a disturbance. If B and β were exactly equal, a Balancing Authority would see no change in ACE following a frequency decline, even though it provided a MW contribution to stabilize frequency.

Bias and Frequency Response are both negative numbers. In other words, as frequency drops, MW output (β) or desired output (B) increases. Both are measured in MW/0.1Hz

Important Note: When people talk about Frequency Response and Bias, they often discuss them as positive values (such as "our Bias is 50MW/0/1Hz"). Frequency Response and Bias are actually negative values.

Early research (Cohn) found that it is better to be over-biased (absolute value of B greater than the absolute value of β) than to be under-biased.

7 Select from list found at: http://www.nerc.com/commondocs.php?cd=2

Detailed Discussion

Primary Control (Frequency Response)

Background

Primary Control relates to the supply and load responses, including generator governors (speed controls) that stabilize Interconnection frequency whenever there is a change in load-resource balance. Primary Control is provided in the first few seconds following a frequency change and is maintained until it is replaced by AGC action. Frequency Response (or Beta) is the more common term for Primary Control. Beta (β) is defined by the total of all initial responses to a frequency excursion.

Figure 6 shows a trace of the Western Interconnection's frequency resulting from a generating unit trip. The graph plots frequency from 5 seconds prior to the loss of a large generator until 60 seconds thereafter.

NERC references three key events to describe such a disturbance. Point A is the pre-disturbance frequency, typically close to 60 Hz. Point C is the maximum excursion point, which in this WECC example occurs about 5–8 seconds after the loss of generation. Point B is the settling frequency of the Interconnection.

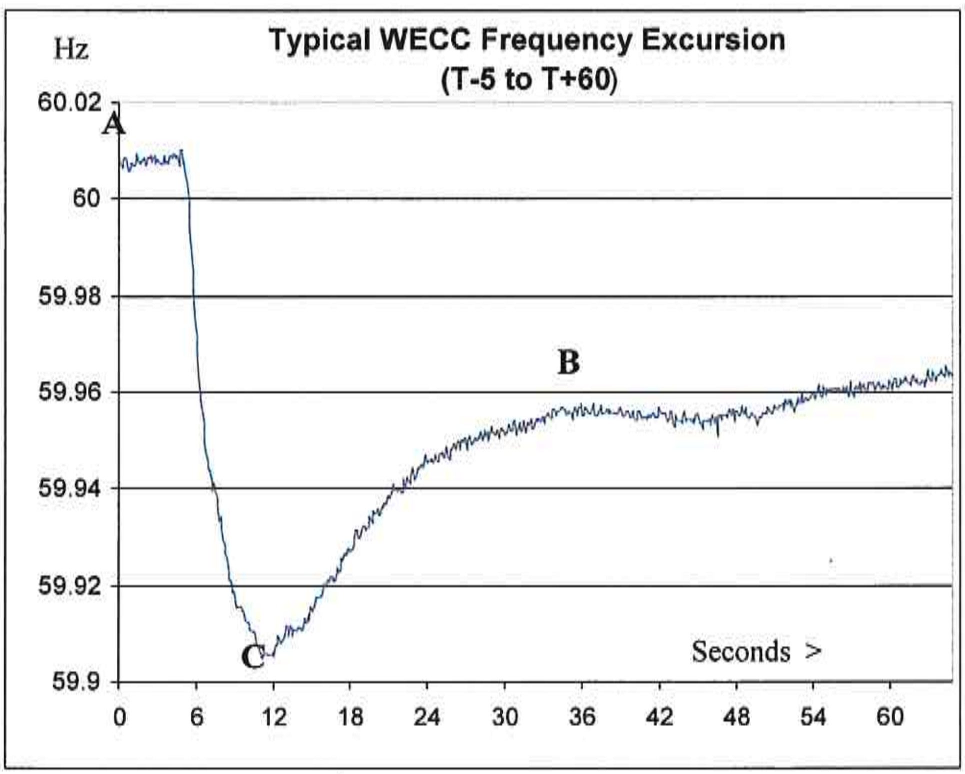


Figure 6 — WECC Frequency Excursion

Exhibit Bickett-3

As discussed earlier, there are two groups of "resources" that arrest a decline in frequency due to a loss of generation.

- A given portion of Interconnection demand is composed of motor load, which draws less energy when the motors slow down due to the lower frequency.
- Generators have governors that act much like cruise control on a car. If the generators on the Interconnection start to slow down with the frequency decline, their governors supply more energy to the generators' prime movers.

Generator Governors (Speed Controls)
The most fundamental, front-line control of frequency in AC electric systems is the action of generator governors. Because of the sensitivity of generators and loads to frequency, and to prevent frequency instability and possible collapse, it is important to maintain stability of the interconnection operating frequency and responses to changes in it. Governors operate in the timeframe of milliseconds to seconds and operate independently from (and much faster than) system operator actions or those of AGC. They protect from the effects of frequency when too high, but the vast majority of their benefit comes from assisting when frequency has dropped too low, especially in cases where loss of generation causes abrupt decreases in interconnection frequency.

Slope – Governors act to cause generators to try and maintain a constant, stable system frequency (60 Hertz in North America). They do this by constantly regulating (modulating) the amount of mechanical input energy to the shaft of the electric generator. The degree of this modulation is called "slope", and is measured in percent of frequency change to cause full generator capability to be exerted against the frequency error. A typical slope is 5%, which means that if frequency error is 5% (or 3 Hz) the full output of the generator would be used (or attempt to be used) to counteract the frequency error. Frequency errors are more typically in the range of 0.01% (.06 Hz, or 60 mHz), so governor action usually is a much smaller fraction of a unit's output capability. It must also be recognized that, while most generators can reduce output considerably in response to their governor's actions, increasing output is more problematic since many generators may already be near the top of their output capability when low frequency causes their governor to request more output. Thus, if there is no "headroom" available on a generator's output, the governor will be able to do little to increase that output and help stabilize low frequency.

Deadband – The second general characteristic of governors is "deadband". This simply means that until frequency error is beyond a threshold, the governor ignores it. When frequency error exceeds the threshold (.036 Hz, or 36 mHz by convention) the governor becomes active. It is worth noting that for older, mechanical-style governors the deadband may be larger and has associated with it the mechanical lash that exists in mechanically-coupled devices.

Without governor action, loss of generation would result in frequency that would not stabilize until the interconnection load – frequency characteristic resulted in a (reduced) load that matched the remaining generation output. This point could be at very low frequency and could result in cascading outages or complete frequency collapse, a very undesirable outcome in terms of the cost to society and potential equipment damage.

The combination of governor response and load – frequency response - is the "beta" (β), or frequency response characteristic, of a Balancing Area. This is the characteristic which AGC attempts to mimic in its use of the frequency bias ("B") parameter in determining ACE. The net of all Balancing Area frequency responses manifests as the interconnection frequency response, discussed in Frequency Response Trends.

Frequency Response Trends

Studies over the past 30 years have shown a general decline in Frequency Response in the Eastern Interconnection, and mixed results in other interconnections. In theory it should be increasing with increasing load and generation. Since 1994, Eastern Interconnection Beta has declined roughly 20 percent even though it should have been increasing in proportion to a 20 percent increase in customer demand. Figure 7 shows the recent trend in Beta.

While this trend is of concern, some caution is needed. Early studies were based on limited samples of generally large events. Such events would generally trigger more Primary Control.

The underlying reason for the proposed Frequency Response Standard is to develop an objective method to calculate Beta for all Balancing Authorities and Interconnections. For example, it is unknown whether the general trend is global or whether there are specific areas with low Frequency Response.

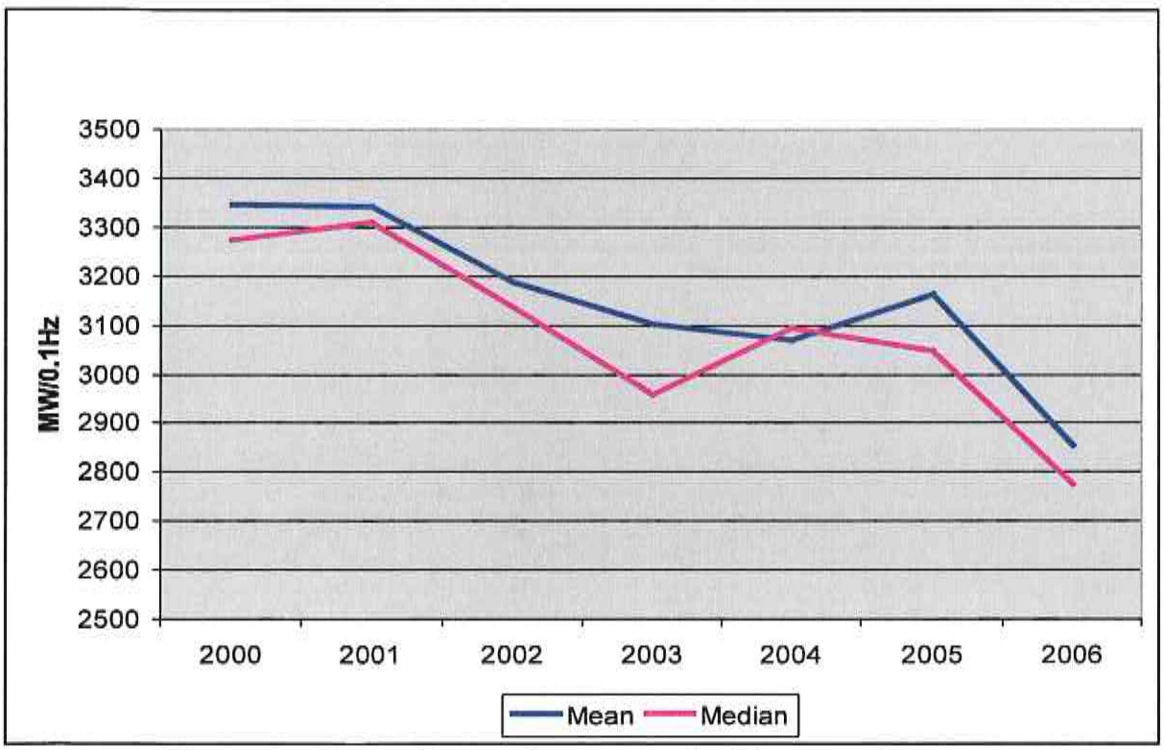


Figure 7 — Recent Eastern Interconnection Frequency Response

Frequency Response Variability

Some have suggested that there should be a standard that requires a minimum amount of frequency response from all Balancing Authorities for all events. Consistency in measuring and controlling this would be problematic.

The calculated beta[8] for a Balancing Authority is based on measuring a relatively small change in Net Actual Interchange coincident with a frequency excursion. Load and generation continuously change in a Balancing Authority. Any random variation in load or generation that happens to occur at the time of the disturbance will greatly misstate the calculated beta for that event. An objective estimate of Balancing Authority beta should be based on 30 or more events dispersed throughout the year. Using the median value will eliminate the impact of misstated individual events.

There is a great deal of variability of Beta or Interconnection Frequency Response by season and day of the week. Beta may be larger during peak periods because there are more contributing generators and motors.

Most observed frequency excursions in the Eastern Interconnection are caused by:

- Generator trips.
- Schedule changes (resulting in significant generation changes) at the top of the hour, particularly during the on-peak to off-peak transitions.
- Pumped storage generation starts/stops.

A given MW-sized event will cause a larger frequency excursion during periods of low Beta than during periods when Beta is higher. As such, some events of a given size will not cause a noticeable change in frequency during peak periods that have a large Beta, yet an event of the same size might cause a significant frequency shift during periods with low Beta.

Figure 8 shows the variability of Interconnection Beta indirectly by tracking the number of sufficiently large[9] frequency excursions by month of the year and day of the week. Notice that there are few frequency excursions during the peak months, but many excursions on the light-load months, and in particular, on weekends. This implies that an objective estimate of Beta must look at many events throughout the year.

8 A capitalized Beta (which looks like a B) typically applies to the Frequency Response of an Interconnection, while small beta (β) applies to the response of a Balancing Authority.

9 28 mHz was chosen as a "benchmark" for frequency excursions in the Eastern Interconnection by the Resources Subcommittee when Beta was 3500MW/0.1 Hz. At this point in time, a 28 mHz excursion was typically associated with the loss of roughly 1000MW.

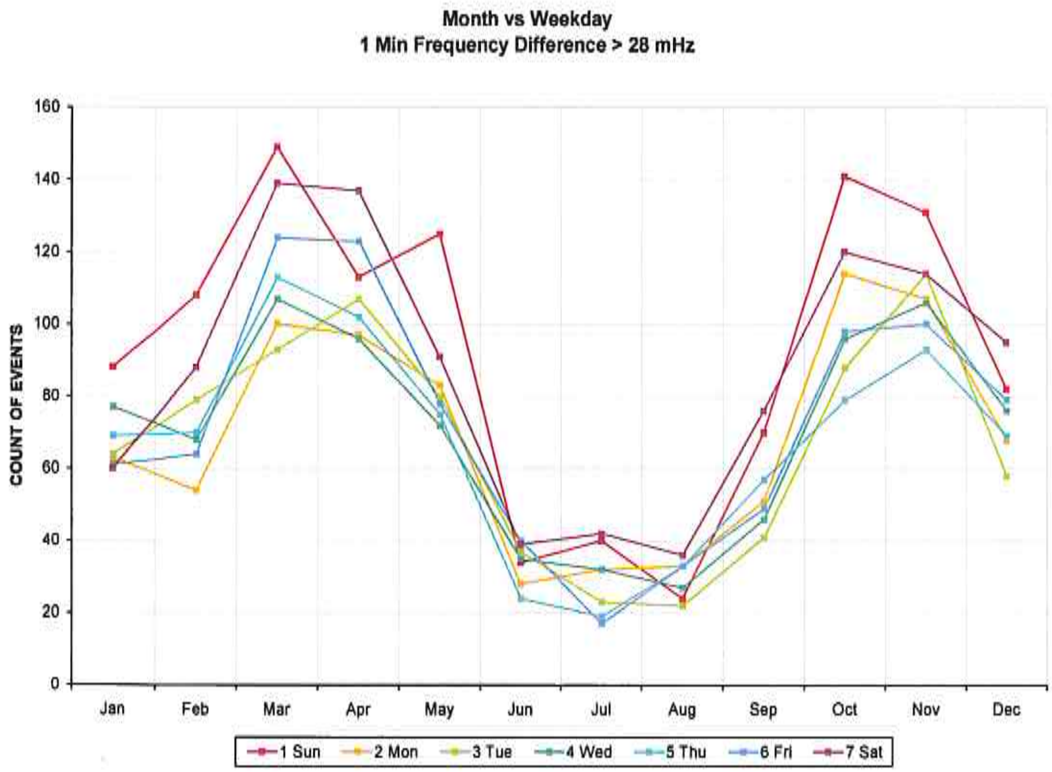


Figure 8 — Frequency Excursions by Month and Day of the Week

Tips on Calculating Frequency Response
The NERC Resources Subcommittee occasionally requests Frequency Response Characteristic Surveys for specific events. The NERC *Frequency Response Characteristic Survey Training Document, contained in the NERC Operating Manual,* has a form for calculating Frequency Response for a particular event.

Balancing Authorities should not rely on one or two surveys to establish a value to be used for their Bias. Statistical theory says about 30 observations are needed to give a large enough sample to have confidence in the results. The median of these samples is a better indicator of central tendency when measuring a highly variable population like Frequency Response events.

Because of the work involved, few Balancing Authorities go through a statistically rigorous approach to calculate their Bias. Most simply use the "1 percent of load" approach. The value in a Balancing Authority properly stating its Bias is to "tune" AGC to the natural response of its load and generation.

So how have Balancing Authorities obtained the observations to be used for calculating their Bias? There really has not been a standard way to do this. In some cases, Balancing Authorities have implemented automatic tools that scan for frequency events and archive data. Others just rely on their operators to spot frequency events and make a log entry somewhere so that someone can go back and pull the appropriate data (either electronic or even paper charts).

The NERC Resources Subcommittee has lists of excursions available to the industry for everyone's use for calculating Frequency Response. On request, they will post such events on their Web page.

Date	Time	ANI "A"	ANI "B"	Frequency "A"	Frequency "B"	Response
1/7/02	13:02	25	7	60.010	59.965	40.0
1/21/02	16:12	-37	-30	59.980	59.962	-38.9
2/16/02	6:07	203	167	60.011	59.97	87.8
2/22/02	9:17	-72	-84	60	59.963	32.4
2/27/02	6:33	18	19	60.01	59.97	-2.5
3/5/02	17:15	-204	-255	59.99	59.928	82.3
3/9/02	21:30	-111	-131	60.01	59.965	44.4
3/22/02	16:15	35	17	60.025	59.971	33.3

34.9	Average Response
36.7	Median Response
8	Number of Events

Table 2 – Frequency Response Calculator

Table 2 demonstrates how a Balancing Authority can go about calculating its Frequency Response from several events. The table is nothing more than a spreadsheet that takes Net Actual Interchange and Frequency at points A and B and calculates both individual and cumulative Frequency Response.

Table 2 is also an embedded spreadsheet. "Double clicking" on the table will open the spreadsheet. If you are interested in saving the sheet to calculate local Frequency Response, all you have to do is open the spreadsheet, then copy and paste it into a regular spreadsheet.

> **New Tool:** NERC is implementing a Frequency Monitoring project developed by the Consortium for Electric Reliability Technology Solutions (CERTS), sponsored by the Department of Energy (DOE). As part of the project, you can receive e-mail notifications associated with frequency excursions that would be candidates for calculating responses. If you are interested, contact your NERC Resources Subcommittee representative.

Once a Balancing Authority calculates its Frequency Response, it must make a decision on what Bias it will report to NERC by January 1 and use in its ACE calculation. The following are the options to consider:

- The best approach is to use a Bias that reflects natural Frequency Response for all the observed excursions.
- If natural Frequency Response is less than 1% of projected peak load or generation, Bias must be set such that it complies with the BAL-003 requirement that the monthly average value of Bias be at least 1% of projected peak load or generation (see standard for details).
- The Control Performance Standard does provide some room for Balancing Authorities to select a Bias as part of a control strategy, provided they observe BAL-003 R2 and R5. For example, Balancing Authorities with large, rapidly-changing ("nonconforming") loads such as arc furnaces that cause problems meeting CPS2 may want to increase their

Bias beyond their natural response. This causes their units to do more regulating (or a decline in CPS1 for the same amount of regulating) as a trade-off for getting larger L10 limits. (The size of CPS2's L10 is related to Bias.)

Unless the process is automated, there is a fair amount of effort required in objectively calculating Frequency Response.

Calculating Frequency Response is not a new requirement. Many Balancing Authorities do this in order to calculate and set their bias. Those that do this manual task understand the challenges involved.

Figure 5 shows actual scan rate response for a medium-sized Balancing Authority for five events in 1998. The chart is a graph of the Balancing Authority's "Tie Deviation" in MWs plotted against time. The chart shows the Tie Deviation from 60 seconds before a frequency excursion until 60 seconds after the excursion.

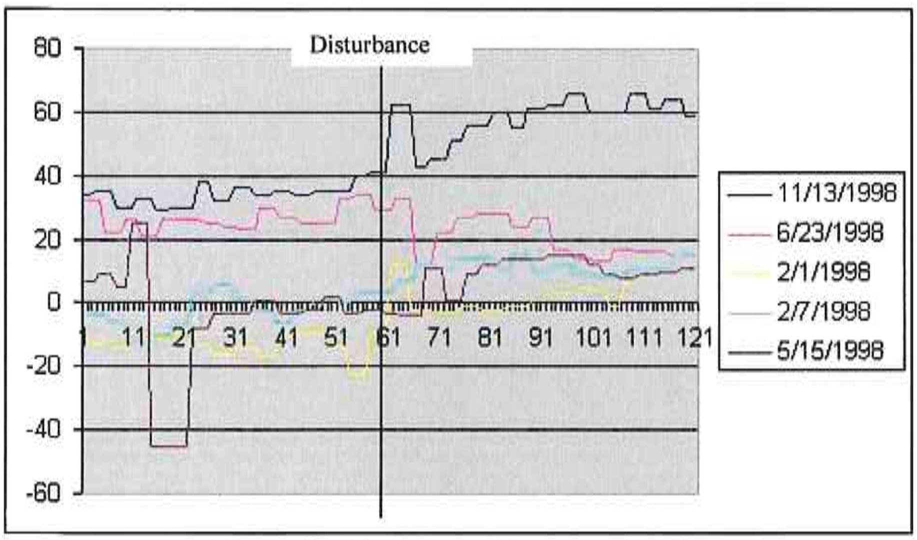


Figure 9 – Frequency Response for 5 Events

For the time being, assume all five frequency excursions were 33 mHz. The reader can refer to the *Frequency Response Characteristic Survey Training Document* for the actual calculation, but Frequency Response is simply:

[MWs deployed /0.1 Hz of frequency deviation]

Since 33 mHz is one-third of 0.1 Hz, it seems all we have to do is multiply the change in Balancing Authority output by 3. For those familiar with the process, two problems immediately arise.

First, the *Frequency Response Characteristic Survey Training Document* says to use the interchange values "immediately before" and "immediately after" the disturbance to derive a value for MWs deployed for the event. The reader is asked to actually determine and write down the "MW deployed" for these events. It is almost certain your answer will be different than another person who reads the same graph. Given a frequency excursion of 33 mHz, a difference in calculation of 5 MW of tie deviation means a difference of 15 MWs in Frequency Response. Obviously, there is a need to be more explicit in the methodology and to find a way to take the subjectivity out of the process.

Second, a scan of Figure 5 shows that the Balancing Authority actually had a negative response for the June 23 event. This brings up another underlying problem with measuring Frequency Response. Short of measuring every generator individually, there is no way to separate Frequency Response from normal load variations for a single event. To remove the effect of load variation at the Balancing Authority level, many events should be measured and a statistical average response calculated. If enough events are captured, the effect of load variations will be reduced (because load swings are equally likely to inflate or decrease the calculated Frequency Response).

- There is significant variation in a single Balancing Authority from event to event. This means that the selection process for events to be measured markedly affects the results. If every Balancing Authority is not working off the same selection criteria or the same set of events, it is likely that results will be inconsistent.
- Some Balancing Authorities calculate their response from paper "Net Interchange" charts. The scale on these charts is such that it is difficult to identify the "blip" that corresponds to the frequency excursion. CPS source data is digital to several decimal places, and thus less subjective.
- Refer back to Figure 5 and consider the manual process that exists today. It is unlikely that given the objective data in the graph that two people calculating response for these events manually would come up with matching answers. Using CPS data takes subjectivity out of the process.
- *The Frequency Response Characteristic Training Document* leaves room for interpretation on the time window to measure. The document talks about using the Interchange and Frequency values "immediately before" and "immediately after" the event. This is subject to interpretation. Using CPS data takes subjectivity out of the process.
- On the average, little automatic generation control (AGC) occurs within a single minute timeframe. Even though there will be some random load and generation swings in each event, their effects will be netted out over many events.

Frequency Response Profiles of the Interconnections

The amount of frequency decline from a lost generator varies based on time of day, the season, as well as the Interconnection. The Frequency Responses of the North American Interconnections are on the order of:

- -2,760 MW / 0.1Hz (Eastern Interconnection)
- -650 MW / 0.1 Hz (Texas Interconnection – ERCOT)

- -1,482 MW / 0.1 Hz (Western Interconnection – WECC)
- -120 MW / 0.1 Hz (Quebec Interconnection)

Important Note: The values in this section are approximations based on currently available data.

The negative sign means there is an inverse relationship between generation loss and frequency. In other words, a loss of 1,000 MW would cause a frequency change on the order of:

- -0.036 Hz (East)
- -0.154 Hz (Texas)
- -0.067 Hz (West)
- -0.833 Hz (Quebec)

Conversely, if 1000 MW of load were lost in an Interconnection, the resulting frequency increase would be similar in magnitude as listed above. In ERCOT it has been observed that typical response to high frequency events is approximately 2/3 of the frequency response for low frequency events.

Figure 10 is a typical trace following the trip of a large generator in the Eastern Interconnection, while Figure 11 is a trace from ERCOT. Notice that governors in the East do not provide the "point C to B" recovery of frequency as they do in the other Interconnections. Another observation in the East is that there is often some decline of frequency towards the end of the first minute following the event. It is believed this is due to setpoint control at both generating stations and in the Balancing Authorities' control systems. More investigation is needed to specifically identify the cause of this behavior.

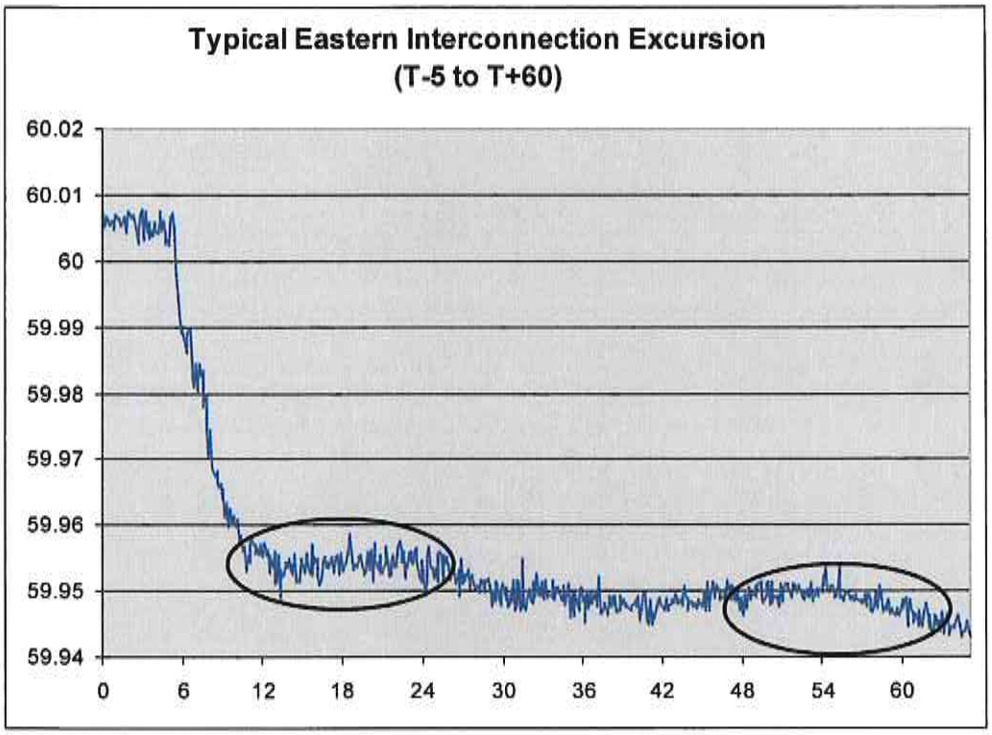


Figure 10 — Typical Eastern Interconnection Frequency Excursion

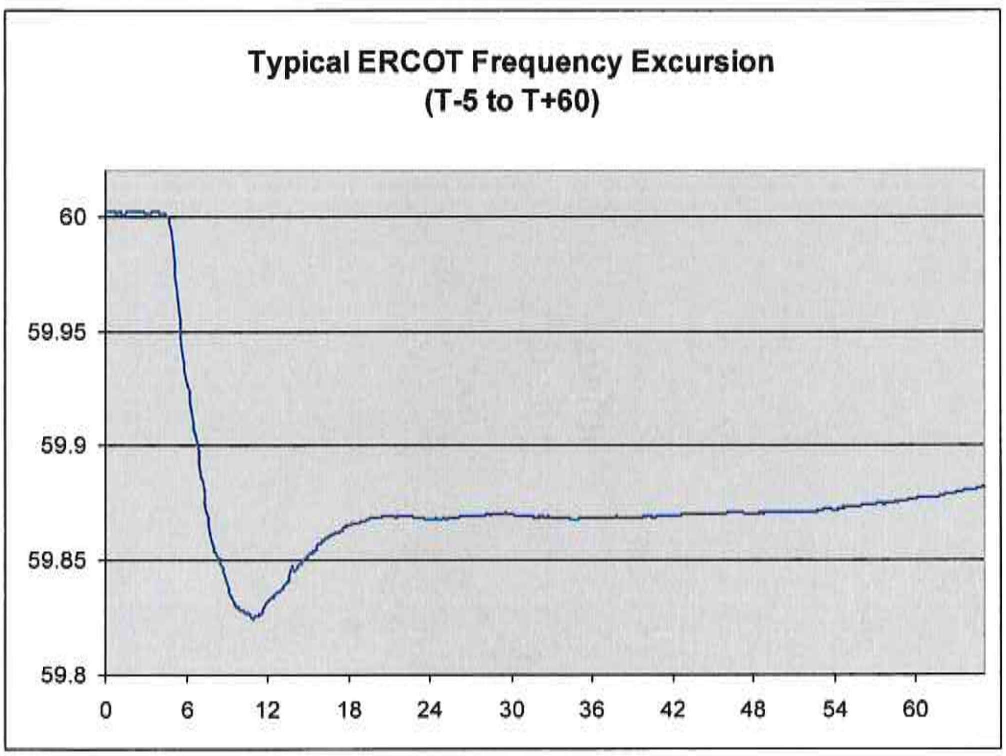


Figure 11 — Typical ERCOT Frequency Excursion

Important Concept: Following a large generator trip, Frequency Response will only stabilize the frequency of an Interconnection, arresting its decline. Frequency will not recover to schedule until the contingent Balancing Authority replaces the lost generation through AGC and reserve deployment.

Annual Bias Calculation

The value in a Balancing Authority properly stating its Bias is to ensure its AGC control system does not cause unnecessary over-control of its generation.

The NERC Resources Subcommittee has lists of excursions available to the industry for everyone's use for calculating Frequency Response. One may have been provided along with this document.

Guidelines in selecting and evaluating events for calculating Bias include:

- If possible, avoid using events where you or a neighboring Balancing Authority caused the frequency decline. Tie-line data typically goes through wide swings when this is the case.
- Ensure events are dispersed throughout the year to get a good representation of "average" response.
- Pick frequency excursions large enough to actuate generator governors. This would require excursions of at least 36 mHz (.036 Hz), because some governor references use this as a deadband setting. With some older governors unable to resolve better than 50 mHz, excursions of at least this magnitude may prove even more useful.

Estimating Load's Frequency Response

As discussed previously, motor load provides frequency response to the Interconnection. The rule of thumb is that this response is equal to 1 to 2 percent of load. Techniques have been developed to observe approximately how much "load" frequency response a Balancing Authority actually has. This technique is explained below.

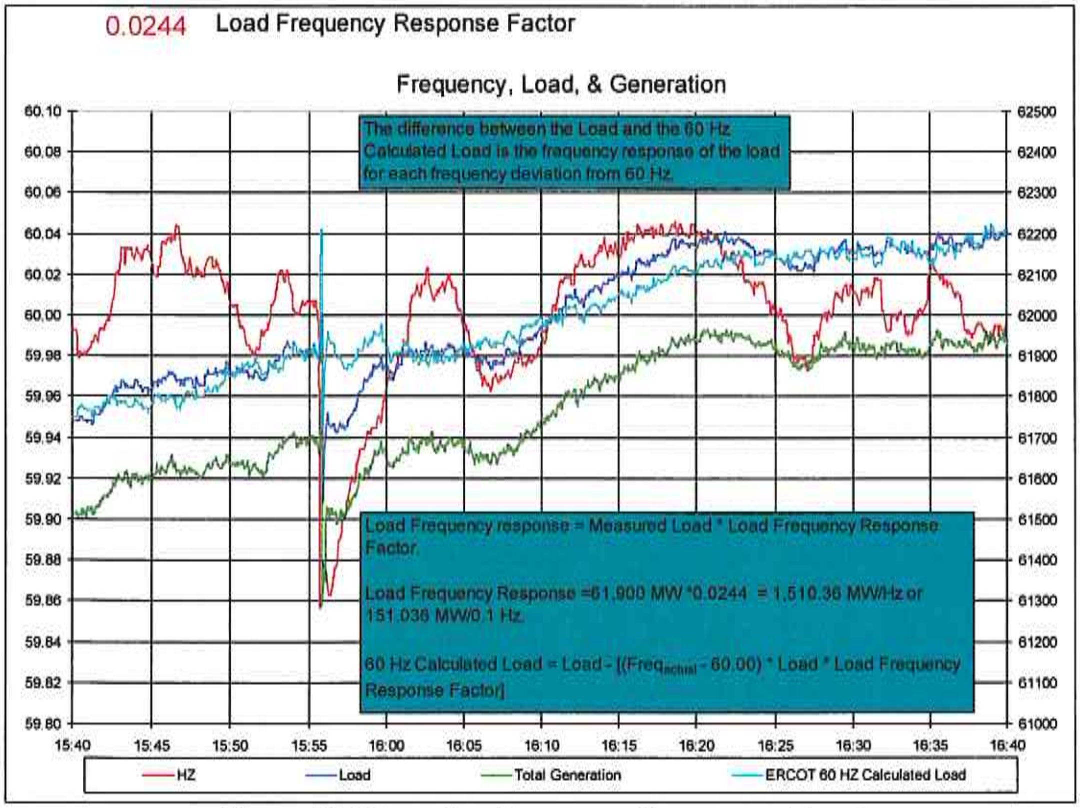


Figure 12 Observing Frequency Response of Load

The cyan trend in **Figure 12** above represents how much load would exist if frequency could be controlled to exactly 60.000 Hz all the time. The difference between the measured load, blue trend and the cyan trend is the frequency response of load. For this event, a 759 MW resource was lost producing a frequency deviation of -0.118 Hz. This calculates to be 759/(0.118*10) = 643 MW/0.1 Hz of frequency response. Of this response, 151.036 MW/0.1 Hz was provided by the load (by multiplying the load by .00244) which leaves the remainder, 492.184 MW/0.1 Hz, provided by resource governor response. The post contingency total generation settled at 61,510 MW a difference of 178.222 MW below the pre contingency generation. The generation to load mismatch post-event is 178.222 MW plus replacing the 580.777 MW of governor response (492.184 * 1.18 = 580.777) that will be withdrawn as frequency returns to 60.00 Hz. If this BA's Bias in the ACE equation had been set exactly at 643 MW/0.1 Hz, ACE would equal -759MW at the B point of this event. AGC would dispatch 759 MW to replace the frequency response of the governors and load which would return the Interconnection to balance at 60.00 Hz. This example is of a "single" Balancing Authority Interconnection but the math works for multiple BA Interconnections as well.

By observing multiple events and adjusting the factor to produce a "60 Hz Load" value that maintains the pre and post event slope of load, a proper value can be determined. Larger deviation frequency events are beneficial to get a clear observation as well as looking at many events. A factor between 0.010 and 0.025 would be reasonable depending on the ratio of motor load vs. non-motor load within the BA boundaries.

Key Points (Primary Control)

- Steady-state frequency is common throughout an Interconnection.
- If frequency is off schedule, generation is not in balance with total load at the load's value for scheduled frequency.
- Arresting frequency deviations is the job of all Balancing Authorities. This is achieved by provision of frequency response through the action of operating governors on generation and other resources able to provide frequency response (e.g., controllable load).
- Frequency Response is the sum of a Balancing Authority's natural load response to frequency and the governor response of generators within the Balancing Authority.
- Frequency Response arrests a frequency decline, but does not bring it back to scheduled frequency. Returning to scheduled frequency occurs when the contingent Balancing Authority restores its load-resource balance.
- Generators should be operated with their governors free to assist in stabilizing frequency.
- Frequency control during restoration is extremely important. That is why system operators should have knowledge of the generators' governor response capabilities during black start.
- All Balancing Authorities have a Frequency Response characteristic based on the governor response of their units and the frequency-responsive nature of their load.
- The amount and rate of frequency deviation depends on the amount of imbalance in relation to the size of the Interconnection.
- Frequency Bias is a negative number (Balancing Authority output increases as frequency declines) expressed in MW/0.1Hz.
- The typical (best) way to calculate Frequency Response is to observe the change in Balancing Authority output for several (many) events over a year.
- A Balancing Authority should set its Bias to no less than its natural Frequency Response, and to at least 1% of predicted system peak load (or generation) per BAL-003.
- The Eastern Interconnection has a Frequency Response of roughly 2,750 MW/0.1 Hz. This means the loss of a 1,000 MW generator will drop frequency roughly 0.036 Hz.
- The Western Interconnection has a Frequency Response of roughly 1,500 MW/0.1 Hz. This means the loss of a 1,000 MW generator will cause the frequency to drop approximately 0.06 to 0.07 Hz.
- Most Balancing Authorities use the "1% of peak load" method to calculate their Bias. This is roughly twice the observed Frequency Response in the Eastern Interconnection.
- Governors were the first form of control, and remain at the vanguard today. They act to mitigate frequency change.
- AGC supplements governor control by controlling actual tie flows and maintaining scheduled interchange at its desired value. It performs this function in the steady-state,

seconds-to-minutes timeframe, after transient effects (including governor action) have taken place. If bias is greater than actual frequency response, AGC will supplement this response.

- ACE, the main input to AGC, requires frequency and energy interchange data (both actual and scheduled)
- The Frequency Response is declining in the Eastern Interconnection and appears to be declining in the Western Interconnection. One underlying issue is that nobody knows if the decline is spread out among all Balancing Authorities or if there are pockets with substandard response. Neither situation is an immediate threat for steady-state reliability. However, Frequency Response is vital during disturbances and islanding.
- Area frequency response should be measured for two reasons.
  - Most importantly, to gauge the area response to frequency upsets,
  - Secondarily, as a basis for setting B.

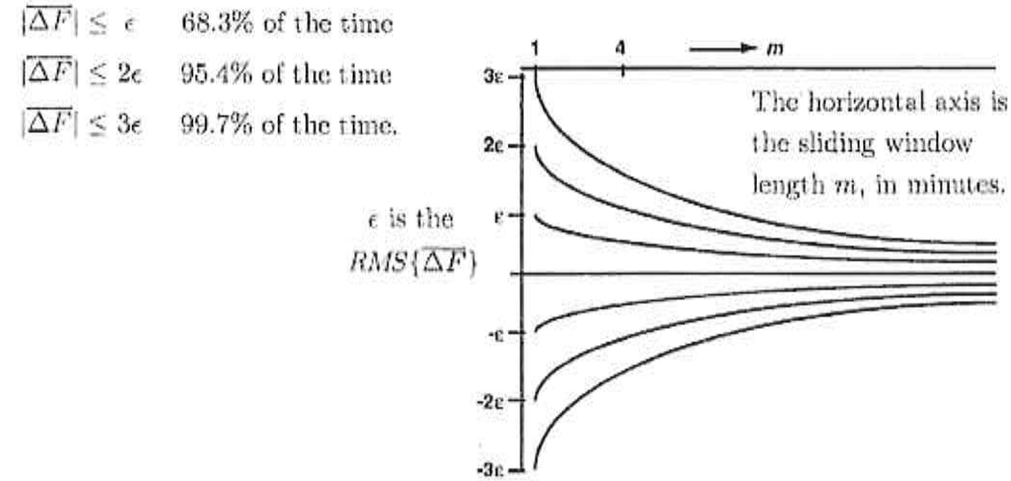
Secondary Control

Background
Secondary Control is the combination of automatic generation control (AGC) and manual dispatch actions to maintain energy balance and scheduled frequency. In general, AGC utilizes maneuvering room while manual operator actions (phone calls to generators, purchases and sales, load management actions) keep repositioning the Balancing Authority Area so that AGC can respond to the remainder of the load and Interchange Schedule changes. The NERC Control Performance Standards are intended to be the indicator of sufficiency of Secondary Control.

Whither the Frequency Profile Requirement?
The most basic indicator of proper Secondary Control action is the character of steady-state interconnection frequency. When the transition was made from the "A" criteria to CPS in 1997, the directive of the NERC Operating Committee was to not allow frequency (deviation) to become any worse than it had been in the past. One measure of this is the root mean square (RMS) of frequency error from schedule. This by itself, however, is a measurement over an indefinite term and may not reveal problems at all averaging intervals. To adequately measure the frequency profile of an interconnection, a statistical method was adopted in which period averages of RMS frequency error were measured and cataloged for periods of a large number of different values. In other words, the average of rolling N-minute RMS averages was computed for many values of N. This results in a defining profile as shown in figures 14a and 14b. Although other values could have been selected, and ideally ALL values should be considered, the averaged values looked at most closely were those for 1 minute and 10 minutes. This was for practical reasons; computing all the interval averages would be computationally burdensome and, arguably, unnecessary if frequency performance could be made (more) random.

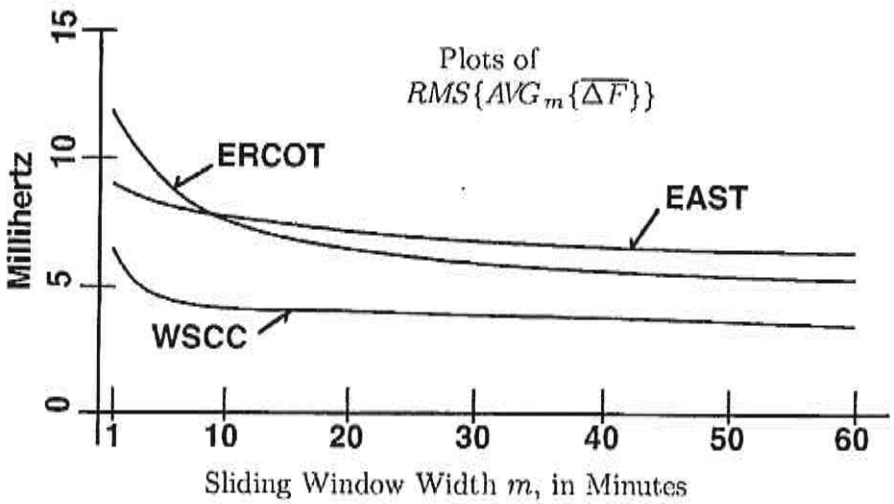
To set values for frequency performance, each interconnection's frequency error was observed using the above method, and each one was characterized, particularly at their 10-minute interval average RMS frequency deviation from schedule. The eastern interconnection measured 5.7 mHz at the 10-minute point. The 1-minute point used to set the CPS standard was derived from an "ideal" error characteristic by the ratio of square roots. This yields 5.4 * sqrt(10) = 18.025

mHz. This value was rounded to the value in use today for the East, 18 mHz. The same technique was used for the WECC and ERCOT interconnections. It is important to realize that CPS1 performance, described in the next section, is only measured at this one "slice" (one minute averaging) of the interconnection's frequency error characteristic. Because of this, there is no assurance that frequency error will be constrained at other averaging points or converge on the ideal characteristic and become more random. CPS2 does impose limits on deviations of ACE at 10-minute averages (intended to help prevent excessive transmission flows due to ACE fluctuations), but this does not assure the desired random behavior, either.



A normally distributed $\overline{\Delta F}$, which had no structure in its trend and was 68.3% of the time within $\pm\epsilon$, would give sliding averages that would be within the narrowest funnel 68.3% of the time. The same averages would be within the second funnel 95.4% and within the largest funnel 99.7% of the time, respectively. The funnels taper at a rate of $1/\sqrt{m}$.

Figure 14a – The ideal ΔF characteristic, for random behavior of Balancing Areas, shows an inverse square-root declining "noise" of frequency deviation as the length of the averaging period increases (EPRI report RP-3550, August, 1996).



Frequency experience in the subject interconnections. Each ordinate point on these curves is the RMS value of the averages of $\overline{\Delta F}$ in windows of width m moved across the data string.

Figure 14b — Illustration of actually-measured ΔF "period average" characteristic (EPRI report RP-3550, August, 1996). Note that these curves are flatter than the ideal, with frequency deviation "noise" remaining significant as the averaging period lengthens. Shown are the actual measured characteristics for the East, WSCC, and ERCOT interconnections. The difference between these and the "ideal" is caused by the distribution of the frequency error being non-random in the real world, while it is assumed to be random in the ideal. Hour-crossing schedule changes, diurnal load fluctuations, pumped hydro operation and other such activity drive this characteristic.

Random (non-coincident) behavior of balancing areas, in total, is important in the above assumptions, because as behavior becomes coincident (behaviors happening at the same time) the curves from which epsilon 1s were extrapolated start to deviate from the shape and predictability of the curves used to derive them. Another way of saying this is that it becomes less and less valid to try to control frequency and measure performance at just one point on the sliding window continuum as coincidence creeps in. One type of coincident behavior is illustrated in Figure 14c below, where time-of-day behaviors relating to diurnal load characteristics and scheduling practices lead to observable clustering of probability of low-frequency events.

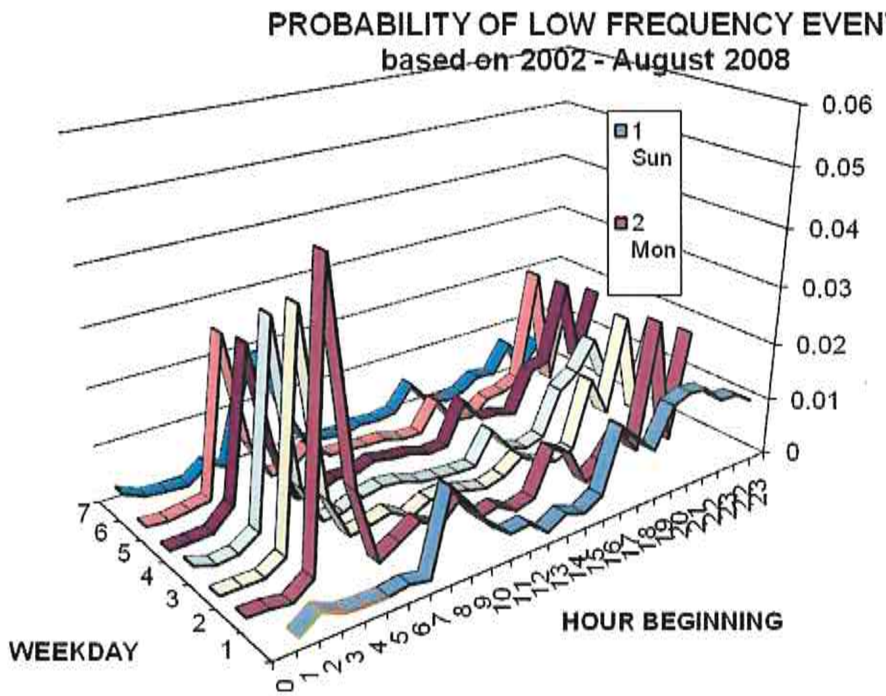


Figure 14c – Probability Distribution for Low-Frequency Events vs. Time of Day

Control Performance Standard 1 (CPS1)
In simple terms, CPS1 assigns each Balancing Authority a share of the responsibility for control of steady-state Interconnection frequency. The amount of responsibility is directly related to Balancing Authority Frequency Bias.

ACE is to a Balancing Authority what frequency is to the Interconnection. Over-generation makes ACE go positive and frequency increase. Negative ACE "drags" on interconnection frequency. "Noisy" ACE tends to cause "noisy" frequency. CPS1 captures these relationships using statistical measures to determine each Balancing Authority's contribution to such "noise" relative to what is deemed permissible.

The CPS1 equation can be simplified as follows:

CPS1 (in percent) = 100* [2 – (a Constant[10])* (frequency error)*(ACE)]

Frequency error is deviation from scheduled frequency. Normally this is deviation from 60Hz. Scheduled frequency is different during a time correction, but for the purposes of this discussion, assume scheduled frequency is 60 Hz.

10 The size of this constant changes over time for Balancing Authorities with variable bias, but the effect can be ignored when considering minute-to-minute operation. It is equal to $-10 * B / \varepsilon_1^2$

Refer to the equation above. Any minute where the average frequency is exactly on schedule or Balancing Authority ACE is zero, the quantity ((frequency error)*(ACE)) is zero. Therefore CPS1 = 100* (2-0), or 200%. This is true whenever frequency is on schedule or ACE is zero.

For any one-minute average where ACE and frequency error are "out of phase", CPS1 is greater than 200 percent. For example, if frequency is low, but ACE is positive (tending to correct frequency error), the Balancing Authority gets extra CPS1 points.

Operating Tip: Frequency is generally low when load is increasing and high when load is dropping. Anticipating and staying slightly "ahead of the load" (and on the assistive side of frequency correction) with your generation will give you high CPS1 scores over the long run.

Conversely, if ACE is aggravating the frequency error, CPS1 will be less than 200 percent. CPS1 can even go negative.

ERCOT Note: The ERCOT Interconnection operates as a single Balancing Authority. ACE for a single Balancing Authority Interconnection will always be "in phase" with frequency error (refer to the ACE Review if you don't see why this is true). This means the largest CPS1 ERCOT can achieve is 200 percent. This occurs whenever ACE or frequency error is zero. CPS1 is a function of "Frequency Squared"

The CONSTANT in the equation above is sized such that if a Balancing Authority's ACE is proportionally as "noisy" as a benchmark frequency noise, the Balancing Authority will get a CPS1 of 100 percent. The minimum acceptable long-term score for CPS1 is 100 percent.

When CPS was established, each Interconnection was given a target or benchmark "frequency noise". This target noise is called "Epsilon 1" or ε_1. Epsilon 1 is nothing more than a statistician's variable that means the RMS (root mean square) value of the one-minute averages of frequency.

The target values (in mHz (millihertz) of frequency noise) for each Interconnection are shown in Table 1 below. The NERC Resources Subcommittee monitors each Interconnection's frequency performance and can tighten (or loosen) the ε_1 values should an Interconnection's frequency performance decline (improve).

Interconnection	Epsilon 1
Eastern	18.0
Hydro Quebec	21.0
Western	22.8
ERCOT	30.0

Table 3 Target Values of "One Minute Frequency Noise"

Exhibit Bickett-3

The Epsilon 1 target initially set for each Interconnection was on the order of 1.6 times historic frequency noise. This should permit Balancing Authorities, performing at historic "average" compliance, to score around 160% for CPS1.

Let's review how CPS1 data can be applied to measure the adequacy of control performance and the deployment of resource-provided services to meet load. NERC refers to these resources as Interconnected Operating Services (IOS). Although there are some differences in definitions, the FERC calls these services Ancillary Services.

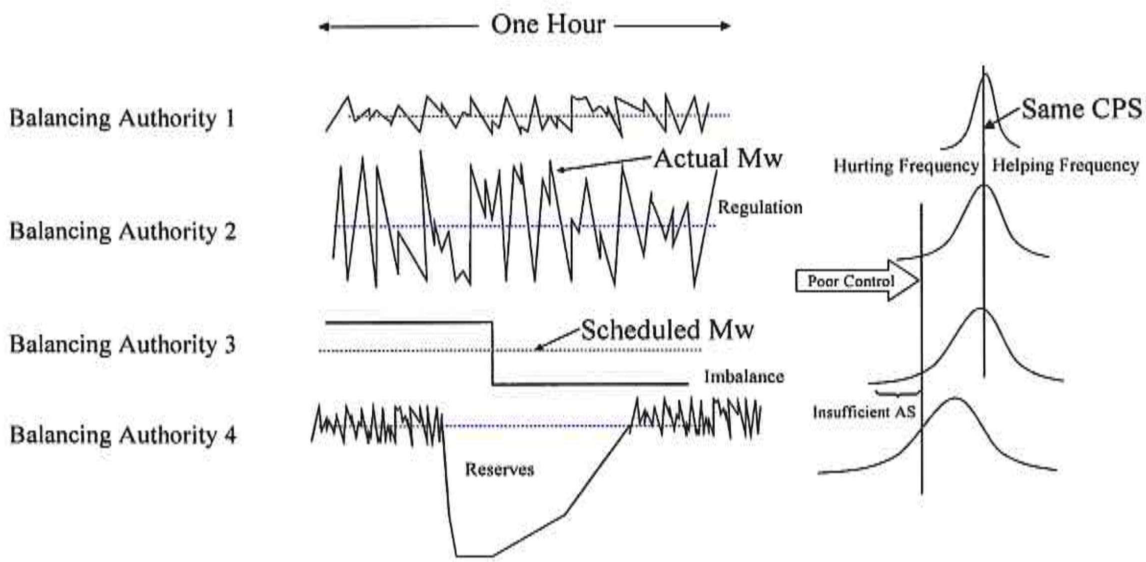


Figure 15 — IOS/Ancillary Service Measured via CPS

Figure 15 depicts ACE charts for one hour for four different Balancing Authorities. Compare the charts for Balancing Authorities 1 and 2. Both Balancing Authorities show good performance for the hour. The difference between them is that the load in Balancing Authority 2 is "noisier".

The "bell curves" to the right of the ACE charts show the distribution of the individual one-minute CPS1 for both Balancing Authorities for the hour. If frequency followed a normal pattern, whereby it fluctuated +/- a few mHz from 60 Hz, the CPS1 curves for Balancing Authority 1 and 2 would look like the "bell curves" to the right of their ACE charts. Both curves would have the same average (about 160 percent CPS1), but Balancing Authority 2's curve would be "wider". In other words, the larger ACE swings would sometimes help frequency back to 60 more than Balancing Authority 1, but sometimes hurt frequency more than Balancing Authority 1.

Even though the average effect of Balancing Authority 1 and 2 on the Interconnection is the same, Balancing Authority 2 sometimes places a greater burden on the Interconnection, as demonstrated by the size of the "left hand tail" of the CPS1 curve. A very long left tail implies poor control of some type (in this case regulation).

Now look at Balancing Authority 3. It is a "generation only" Balancing Authority that is selling 100 MW for the hour. The problem is that it is meeting this requirement by generating 200 MW for the first 30 minutes and 0 MW for the last half of the hour. Again, if frequency conditions are normal, half the time the Balancing Authority will be helping frequency back towards 60 Hz and half the time the Balancing Authority will be hurting frequency. This means the Balancing Authority will get an "Interconnection average" CPS1 score of about 160 percent for the hour. The graph of its CPS1 for the hour will have wider tails, much like Balancing Authority 2. The underlying problem in this case is Imbalance, not Regulation.
The ACE chart for Balancing Authority 4 shows that a generator tripped offline during the hour. If the CPS1 one-minute averages are plotted, the curve will also have wider tails. If the unit that was lost was large, the curve will be "skewed" to the left even further. This is because the unit loss will pull frequency down while ACE is a large negative value.

In each case above there was a deficiency in one of the energy-based IOS (sometimes called ancillary services). The "left tail" of the underlying CPS1 curve captured each situation.

Extremely positive CPS1 (irrational control) is achieved in one of two ways:

- Significant over-generation during low frequency. Low frequency is generally associated with high energy prices. Creating positive inadvertent rather than selling energy into a market is irrational.
- Significant under-generation during high frequency. If a resource is lost during a period of extended high frequency, there are typically many possible suppliers that can be called upon to help correct the situation.

Control Performance Standard 2 (CPS2)
CPS2 is a "safety valve" standard that was put in place when CPS was developed. There was concern that if CPS1 was the only regulating standard, a Balancing Authority could grossly over or under generate (as long as it was opposite the frequency error) and get very good CPS1, yet impact its neighbors with excessive flows.

Table 4 shows the general relationship between Balancing Authority size and the size of the L_{10} band for the Eastern Interconnection. The table assumes the Balancing Authorities use the "1% of load" method to determine their Bias obligation.

BA Size (MW)	$L_{(10)}$ (MW)
10	2
50	5
100	7
250	12
500	17
1000	23
2500	37
5000	52
10000	74
15000	91

Table 4 Approximate L10 Limits vs. Balancing Authority Size (Eastern Interconnection)

Balancing Authorities using variable Bias have L_{10} limits that change slightly throughout the day.

CPS2 says that for each 10-minute period, the average ACE for a 1000 MW Balancing Authority must be less than 23 MW. Any clock 10-minute period (there are six per hour) greater than 23 MW (no matter if it's 1 MW more or 100 MW more) is a violation of the limit for that 10-minute period. Performance requires that there be no violations in at least 90% of the 10-minute periods of a month and is calculated by:

CPS2 (percent) = 100 * (periods without violations)/(all periods in the month)

The minimum acceptable CPS2 for a month is 90%. This means that on the average, a Balancing Authority may have roughly one violation ever other hour and still pass CPS2.

The actual L10 limits change slightly each year, based on bias calculations submitted to NERC. These limits can be found on the NERC Resources Subcommittee web page.

Quick Review:

- CPS1 assigns each Control Area a share of the responsibility for control of Interconnection frequency.
- CPS1 is a yearly standard that measures impact on frequency error, with a 100 percent minimum allowable score.
- CPS2 is a monthly standard intended to limit unscheduled flows.
- The minimum allowable CPS2 score is 90 percent.

Tertiary Control

The UCTE Operation Handbook defines Tertiary Control as any (automatic or) manual change in the working points of generators (mainly by re-scheduling), in order to restore an adequate

SECONDARY CONTROL RESERVE at the right time. This would include actions such as adjustments to scheduled interchange and deployment of additional generation resources.

Understanding Reserves

There is often confusion when operators and planners talk about reserves. One major reason for misunderstandings is a lack of common definitions. NERC's definitions have changed over time. In addition, most NERC Regions developed their own definitions. Capacity obligations have historically been the purview of state and provincial regulatory bodies, which means there are many different expectations and obligations across North America.

The second area of confusion concerning reserves deals with the limitations of each Balancing Authority's energy management system (EMS). Common problems include:

- Counting all "headroom" of on-line units as spinning reserve, even though it may not be available in 10 minutes.
- No intelligence in the EMS regarding load management resources.
- No corrections for "temperature sensitive" resources such as gas turbines.
- Inadequate information on resource limitations and restrictions.
- Reserves which may exist and are deployed outside the purview of the EMS system.

In order to foster discussion and develop a more uniform understanding of the reserve data, the following definitions are provided in this reference. Refer to **Figure 16** to better understand the definitions.

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Curtailable Load: Load that can be disconnected from the system with assurance in less than one hour.

Frequency-Responsive Reserve: On-line generation with headroom that has been tested and verified to be capable of providing droop <= 6% with a deadband <= 36 mHz. Variable Load that mirrors governor droop and deadband may also be considered Frequency Responsive Reserve. In most cases, only portions of a, b and c in Figure 16 qualify as Frequency Responsive Reserve.

Interruptible Load: Load under direct control of an operator that can be interrupted within 10 minutes.

Nonspinning Reserve: Operating Reserve capable of serving demand or Interruptible Demand that can be removed from the system, within 10 minutes. (This is c in Figure 16)

Operating Reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. (This is a+b+c+d+e in Figure 16).

Other Reserve Resources: Resources that can be brought to bear outside the continuum of Figure (i.e. on four hours' notice).

Planning Reserve: The difference between a Balancing Authority's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Projected Operating Reserve: This is a+b+c+d+e in Figure for those resources expected to be deployed (or available in the time windows in Figure 16) for the point in time in question.

Regulating Reserve: An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. (This is "a" in Figure 16 .)

Replacement Reserve: (This is d+e in Figure 16). NOTE: Each NERC Region sets times for reserve restoration, typically in the 30–90 minute range. The default contingency reserve restoration period is 90 minutes after the disturbance recovery period.

Spinning Reserve: Unloaded, synchronized, resource, deployable in 10 minutes. (This is b in Figure 16).

Supplemental Reserve Service: Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes. An ancillary service identified in FERC Order 888 as necessary to affect a transfer of electricity between purchasing and selling entities. Also referred to as non-spinning reserve. This is effectively FERC's equivalent to NERC's Non-Spinning reserve (c in Figure 16).

Much like parts kept in a storeroom, reserves are meant to be used when the need arises. Reserves can be low for short periods of time due to plant equipment problems and unit trips. Reserves can also be misstated. It is important to look at other indicators to determine the ultimate course of action, such as:

- Is the Balancing Authority(s)' ACE predominantly negative for an extended period?
- Is frequency low (more than 0.03 Hz below scheduled frequency)?
- Are reserves low in multiple Balancing Authorities?
- Is load trending upward (are higher loads anticipated)?

Based on the duration and severity of the situation, action steps would include:

- Verify reserve levels
- Follow EEA
- Direct Balancing Authority(s) to take action to restore reserves
- Redistribute reserves

Exhibit Bickett-3

- Shed load where appropriate if the Balancing Authority or Transmission Operator cannot withstand the next contingency.

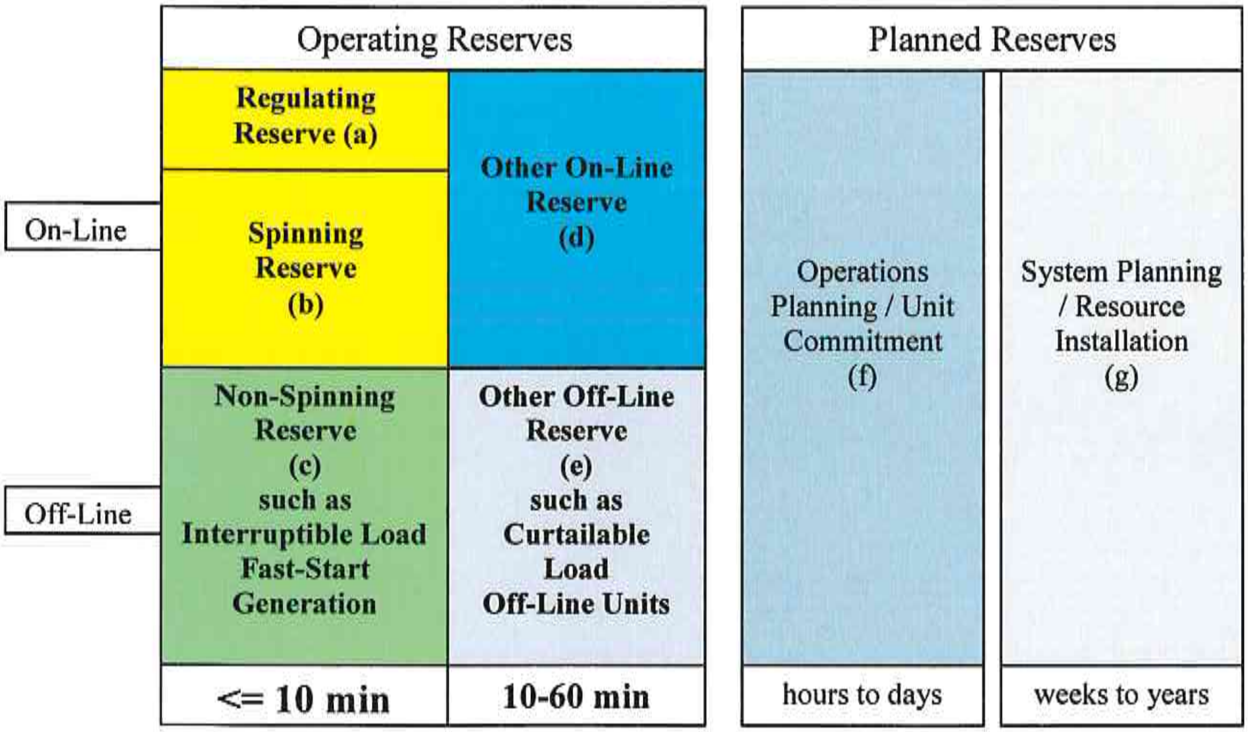


Figure 13 Reserves Continuum

Measuring Performance rather than the Commodity
The traditional measure of resource adequacy is to track operating reserves. A simplified calculation for reserves is Balancing Authority's generating capability minus customer demand. There are actually several different types of reserves (spinning, non-spinning, regulating, contingency, replacement), but all are intended to maintain or restore load-generation balance in different windows of time.

There are four underlying problems with determining adequacy by measuring reserves as a commodity rather than the performance or outcome (restoring load-generation balance):

- Reserves are almost always misstated. Demand forecasts are not precise and projected generating capability may be based on ideal conditions.
- Because of the differing requirements across the country (for example, planning reserve obligations are typically the purview of state commissions) the industry has no standard definition for reserves or process for verifying reserves.
- Not all Balancing Authorities need the same amount and type of Operating Reserves. Balancing Authorities with large arc furnace loads need more regulating (quick maneuvering) generation than others. Balancing Authorities that can import power from

multiple directions need less reserve than a Balancing Authority that has only one neighboring Balancing Authority. Balancing Authorities with less reliable generators or very large generators need more reserves. Balancing Authorities with a preponderance of one fuel source for its generation should have more reserves than neighbors with more diverse fuel supplies.

- Rate and quality of response by reserves vary among different generators and are not always predictable. Actual rate of response is often smaller than the value specified for the unit, and other factors, such as the time delay before generators start responding needs to be considered. Balancing Authorities without methods to accurately evaluate and mitigate issues in regulation response need more reserves.

Even if a Balancing Authority has adequate reserves, it may fail or be unable to deploy them when needed. If, however, a Balancing Authority continuously balances load and resources within objective bounds, it demonstrates through performance that it has enough reserves to meet its needs and fulfill its obligations to the Interconnection.

Time Control and Inadvertent Interchange

Background

There is a strong interrelationship between control of Time Error and Inadvertent Interchange. Time Error occurs when one or more Balancing Authorities has imprecise control, causing average actual frequency to deviate from scheduled frequency. The Bias term in the ACE equation of the remaining Balancing Authorities causes control actions that result in flows between Balancing Areas in the opposite direction. The net accumulation of all these interchange errors is referred to as Inadvertent Interchange. Inadvertent Interchange represents the amount by which actual flows between Balancing Authority Areas and the remainder of the Interconnection differs from the intended or scheduled flows.

Time Control

As noted earlier, frequency control and balancing control are not perfect. There will always be some errors in tie-line meters. Due to load and generation variation, net ACE in an Interconnection cannot be maintained at zero. This means that frequency will vary from 60 Hz over time.

An Interconnection may have a Time Control process to maintain the long term average frequency at 60 Hz. While there are some differences in process, each Interconnection that exercises time control designates a Reliability Coordinator as a "Time Monitor" to coordinate Time Control.

Time Error Corrections are initiated when long-term average frequency drifts from 60 Hz. In the Eastern Interconnection, a 0.02Hz offset to scheduled frequency corrects 1.2 seconds on the clock for each hour of the Time Error Correction, provided the offset scheduled frequency is achieved.

There has been an ongoing debate on the need for Time Error Corrections. The numbers of TECs do provide a benchmark for the quality of frequency control and also an early warning of chronic balancing problems. While the value of Time Control is debatable from a reliability perspective, nobody can say with assurance who or what would be impacted if NERC and NAESB halted the practice of TECs.

Inadvertent Interchange

Inadvertent Interchange is net imbalance of energy between a Balancing Authority and the Interconnection. The formula for Inadvertent Interchange is:

$$NI_I = NI_A - NI_S$$

Where,

> NI_A is Net Actual Interchange. It is the algebraic sum of the hourly integrated energy on a Balancing Authority's tie lines. Net Actual Interchange is positive for power leaving the system and negative for power entering.

NI_S is Net Scheduled Interchange. It is defined as the mutually prearranged net energy to be delivered or received on a Balancing Authority's tie lines. Net Scheduled Interchange is positive for power scheduled to be delivered from the system and negative for power scheduled to be received into the system.

Inadvertent Interchange and can be divided into two categories, described below.

Primary Inadvertent
Primary Inadvertent Interchange is caused by problems or action from within a given Balancing Authority. Primary Inadvertent Interchange occurs due to the following:

- Error in Scheduled Interchange
  - Improper entry of data (time, amount, direction, duration, etc...)
  - Improper update in real-time (TLR miscommunication etc...)
  - Ramp procedures
  - Miscellaneous (phantom schedules, selling off the ties, etc...)
- Error in Actual Interchange (meter error)
  - Loss of telemetry
  - Differences between real-time power (MW, for ACE), and energy (MWhr), integrated values
- Control Error or Offset
  - Load volatility and unpredictability
  - Generation outages
  - Generation uninstructed deviations
  - Physical rate-of-change-of-production limitations
  - Deliberate control offset to reduce inadvertent energy balances

Secondary Inadvertent
Balancing problems external to a Balancing Authority will cause off-schedule frequency. If frequency is low, the bias term of the ACE equation will cause a Balancing Authority to slightly over-generate (after initial effects, such as governor response and load damping, stabilize) to stabilize frequency. Conversely, if frequency is high, the bias term of the ACE equation will cause a slight under-generation. This intentional outflow or inflow to stabilize frequency due to problems outside the Balancing Authority is called Secondary Inadvertent Interchange.

Quick Review: If one or more Balancing Authorities have a control problem, it will cause them to have a large Primary Inadvertent Interchange. This may also cause off-normal frequency, which spreads Secondary Inadvertent Interchange to the other Balancing Authorities. The off-normal frequency then results in accumulated Time Error, which may trigger Time Error Corrections.

Frequency Correction and Intervention

Background

There are several requirements in the NERC reliability standards that tell the Balancing Authority, Transmission Operator and Reliability Coordinator to monitor frequency and control frequency. The standards do not provide specific guidance on what is normal frequency and under what conditions the operator should intervene. This section provides guidance based on the underlying research done to support the draft Reliability Based Control Standard. The trigger points below are designed for the Eastern Interconnection. There may be differences in the other Interconnections based on their field trial experience.

As noted early in this document, this information is provided for guidance and understanding. It should not be used for compliance purposes and does not establish new requirements or obligations.

The Balancing Authority ACE Limit (BAAL) is the ACE-frequency combination equivalent to instantaneous CPS1 of -572%[11]. In general, if one or more of the RC's Balancing Authorities is beyond the BAAL for more than 15 minutes, the RC should contact the Balancing Authority to determine the underlying cause. As frequency diverges more from 60 Hz, the RC and BA should be more aggressive in their actions.

The primary responsibility of the RCs under the draft Reliability Based Control standard is protection of frequency. Suggested actions are outlined below.

11 As a clarification, the BAAL is based on a snapshot CPS1 calculation that uses deviation from 60Hz rather than deviation from scheduled frequency.

Short-Term Triggers (Reliability Coordinators)

Frequency	What	Actions
60.5	FRL High	1,4
60.2	FAL High	1,3
60.05 (>10 minutes)	FTL High	1,2
60.05 (>5 minutes	FTL High	1,
59.95 (>5 minutes)	FTL Low	1,
59.95 (>10 minutes)	FTL Low	1,2
59.91	FAL Low	1,3
59.82	FRL Low	1,4

1. Look for BAs within your area beyond BAAL. Direct correction and log. RCs to notify BAs.

2. Call Other RCs, communicate problem if known. Search for cause if none reported. Notify time monitor of findings. Time monitor to log. Direct BAs beyond BAAL to correct ACE.

3. Direct all BAs with ACE hurting frequency to correct. Time Monitor to notify Resources Subcommittee (after the fact).

4. Evaluate whether still interconnected. Direct emergency action.

NERC Tools

Short Description of the RS-Sponsored Tools

Exhibit Bickett-3

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Review Questions

The questions below are intended as a resource for the development of local training programs. Trainers are encouraged to submit additional questions to balancing@nerc.com.

Primary Control

1) System frequency:
   a) Measures load-resource balance in an Interconnection or island
   b) Changes in direct relation to generator voltage
   c) Varies from Balancing Authority to Balancing Authority
   d) All of the above
2) How does a Balancing Authority determine the frequency Bias it should use
   a) The same value of the previous year unless a new generator is added
   b) The greater of generation or load multiplied by the L10 limit
   c) Measure the actual response to several frequency deviations
   d) None of the above
3) Generation external to your Balancing Authority has tripped. Which of the following would you expect to see?
   a) Frequency above 60 Hz
   b) Increased net interchange out
   c) Reduced net generation on your system
   d) All of the above
4) The frequency Bias setting used by a Balancing Authority -may be calculated:
   a) As a fixed value
   b) As a variable value
   c) Using a percentage of governor droop from jointly owned units for dynamic scheduling or pseudo-tie control
   d) All of the above
   e) None of the above
5) The minimum recommended frequency Bias setting used by a Balancing Authority that serves load is:
   a) 1 percent of the annual peak demand per 0.1 Hz change
   b) 2 percent of the annual peak demand per 0.1 Hz change
   c) 5 MW/0.1 Hz
   d) –5 MW/0.1 Hz

Exhibit Bickett-3

e) None of the above

6) The minimum recommended frequency Bias setting for a Balancing Authority that does not serve native load is:

   a) 1 percent of the estimated maximum generation level for the upcoming year per 0.1 Hz change

   b) 2 percent of the estimated maximum generation level for the upcoming year per 0.1 Hz change

   c) 5 MW/0.1 Hz

   d) –5 MW/0.1 Hz

   e) None of the above

Use the following data to answer questions 7 and 8.

Assume a Balancing Authority's Bias setting is –50 MW/0.1 Hz. ACE is initially 0 and frequency is 60.00 Hz. Suddenly, a disturbance elsewhere drops frequency to 59.96 Hz. If the actual Frequency Response characteristic for your Balancing Authority for this event is –35 MW/0.1 Hz:

7) What direction is the instantaneous inadvertent interchange on your system at 59.96 Hz?

   a) Received into your system

   b) No inadvertent (0)

   c) Delivered out of your system

   d) None of the above

8) What is the direction of your instantaneous ACE at 59.96 Hz?

   a) Received into your system

   b) ACE is zero

   c) Delivered out of your system

   d) Not necessarily any of the above

9) All generator governors have a droop setting. NERC recommends all generator governors be set at a 5% droop. What does a 5% governor droop setting mean?

   a) The generating unit is allowed to move 5% of its rated load for a frequency deviation of 0.1 Hz

   b) The generating unit is set to cover 5% of the Balancing Authority system load in response to a frequency deviation of 0.1 Hz

   c) The generating unit will cover 5% of its rated load in a ten-minute period in response to a frequency deviation of 0.1 Hz

d) The generating unit will cover its entire load range (0 MW to full load) for a 5% change in frequency

e) None of the above

10) The emergency reserve inherent in the Interconnection's Frequency Response is to be used:

a) Whenever a Balancing Authority cannot afford emergency assistance

b) Only as a temporary source of emergency energy

c) For a period of time not to exceed six hours in a single 24-hour period

d) After all neighboring systems have been polled for emergency capacity availability

11) When providing a certain type of regulation service, a Balancing Authority must incorporate the frequency Bias setting of the Balancing Authority being controlled into its ACE equation. This type of regulation service is known as:

a) Supplemental regulation service

b) Secondary regulation service

c) Overlap regulation service

d) None of the above

12) When providing a certain type of regulation service for another Balancing Authority, the providing Balancing Authority uses only its own frequency Bias setting in its ACE equation. It does not incorporate the frequency Bias of the Balancing Authority for which it is providing regulation service. This type of regulation service is known as:

a) Primary regulation service

b) Supplemental regulation service

c) Time correction regulation service

d) Overlap regulation service

e) None of the above

13) A 1,100 MW generator trips in New York causing a large frequency deviation in the Eastern Interconnection. The NERC survey used to measure the response of every Balancing Authority to the deviation is called the:

a) Area Interchange Error survey

b) Control Performance Standard survey

c) Frequency Response Characteristic survey

d) None of the above

14) If a disturbance reduced the frequency by 0.04 Hz and your Balancing Authority frequency Bias was –100 MW/0.1 Hz, how many MW would your system initially contribute to correcting the problem?

a) 400 MW

b) 0.4 MW

c) 4.0 MW

d) 40 MW

15) Frequency Bias and Frequency Response are:

a) Expressed in MW/0.1 Hz.

b) One and the same.

c) Expressed in MW/cycles of deviation.

d) None of the above.

16) Frequency Bias serves to:

a) Determine the frequency "dead band" of .05 to 1.0 in establishing ACE.

b) Determine MW of response obligation to a given change in frequency.

c) Determine the amount of time error to be automatically corrected by AGC.

d) None of the above is correct.

17) You are doing a perfect job of maintaining a load-resource balance. A large generator in another Balancing Authority has tripped and frequency has dropped to 59.9 Hz. Your frequency Bias is –50 MW/0.1 Hz. If you have done an equally perfect job of setting your frequency Bias, your ACE should be:

a) + 50 MW

b) 0 MW

c) –50 MW

d) None of the above

18) A 1% change in frequency will typically lead to what percent change in the total load?

a) No change

b) 0.1%

c) 1%

d) 2%

19) A governor droop setting is such that the MW output changes by 25 MW for a 0.12 Hz change in system frequency. The maximum output of the unit is 500 MW. What is the value of the droop characteristic? (Nominal frequency is 60 Hz.)

a) 1%

b) 1.2%

c) 4%

d) 5%

20) A power system has ten units on governor control. The units have different capacities (max MW output) and droop settings. The biggest adjustments in MW output in response to a frequency disturbance will be provided by units that have:

a) Large capacity; large droop setting
b) Large capacity; small droop setting
c) Small capacity; large droop setting
d) Small capacity; small droop setting

21) The frequency response characteristic of a power system is defined as:

a) The nominal frequency of the system; 60 Hz in North America
b) The change in Interconnection frequency for 100 MW changes in load or generation
c) The percentage change in system output for a 0.1% change in system frequency
d) The MW change in system output for a 0.1 Hz change in system frequency

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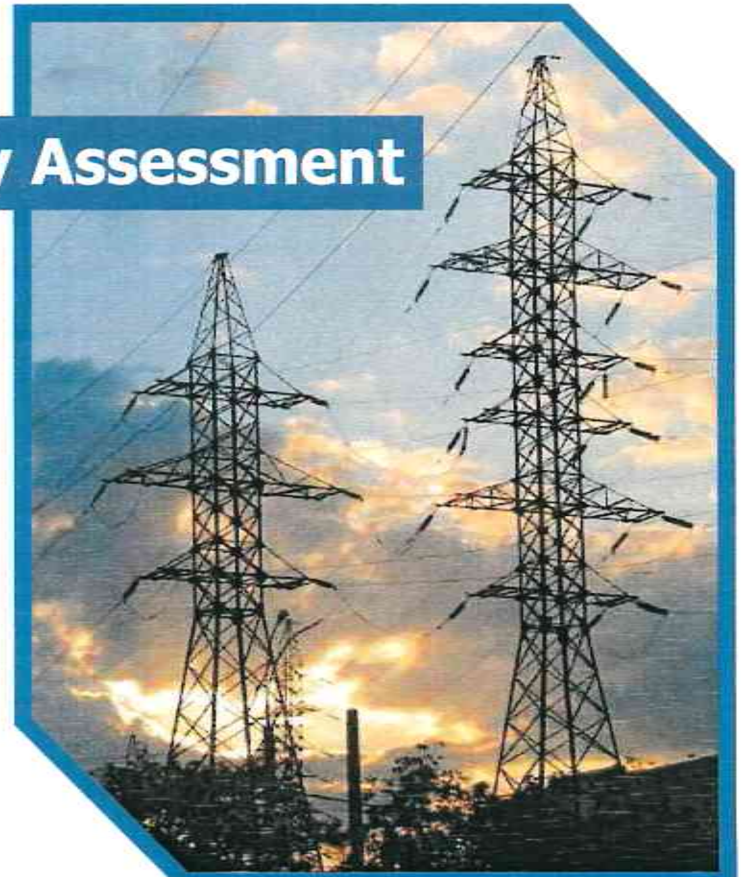
2019 Long-Term Reliability Assessment



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Contents

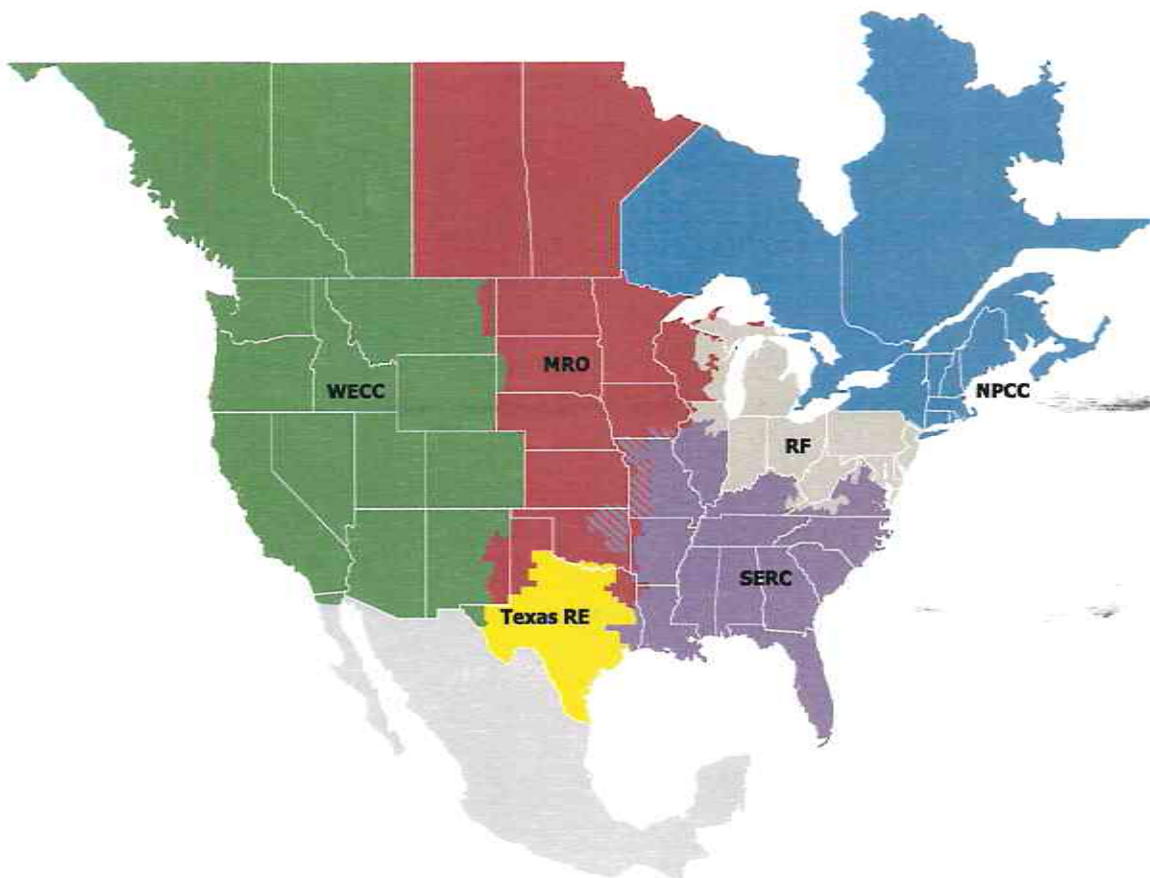
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). The ERO Enterprise's mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



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About This Assessment

Development Process

This assessment was developed based on data and narrative information collected by NERC from the six REs on an assessment area basis to independently assess the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the 10-year assessment period. The Reliability Assessment Subcommittee (RAS) supports the development of this assessment at the direction of NERC's Planning Committee (PC) through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the PC, and the NERC Board of Trustees (Board) subsequently accepted this assessment and endorsed the key findings.

The Long-Term Reliability Assessment (LTRA) is developed annually by NERC in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations, also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[3]

Considerations

Projections in this assessment are not predictions of what will happen but are based on information supplied in July 2019 about known system changes with updates incorporated prior to publication. The assessment period for the *2019 LTRA* includes projections for 2020–2029; however, some figures and tables examine data and information for the 2019 year. The assessment was developed using a consistent approach for projecting future resource adequacy through the application of NERC's assumptions and assessment methods. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the Demand Assumptions and Supply Categories section.

Reliability impacts related to physical and cyber security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through the Electricity-Information Sharing and Analysis Center to promote mechanisms to address these risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and energy, demand response (DR), resource capacity, and transmission projects. Data and information from each NERC Region are also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators and to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

In this LTRA, the baseline information on future electricity supply and demand is based on several assumptions:[4]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2019. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data may be submitted throughout the drafting time frame and included if appropriate (May–November).
- Peak demand and Planning Reserve Margins (PRMs) are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.

1 NERC Rules of Procedure - Section 803

2 Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each RE, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

3 BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

4 Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Exhibit Bickett-4

- Future generation and transmission facilities are commissioned and in-service as planned, that planned outages take place as scheduled, and retirements are scheduled as proposed.
- Demand reductions expected from dispatchable and controllable demand response (DR) programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

- **ERO-Wide Reliability Assessment**
  - Evaluate industry preparations in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policymakers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- **Regional Reliability Assessment**
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on Region-specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

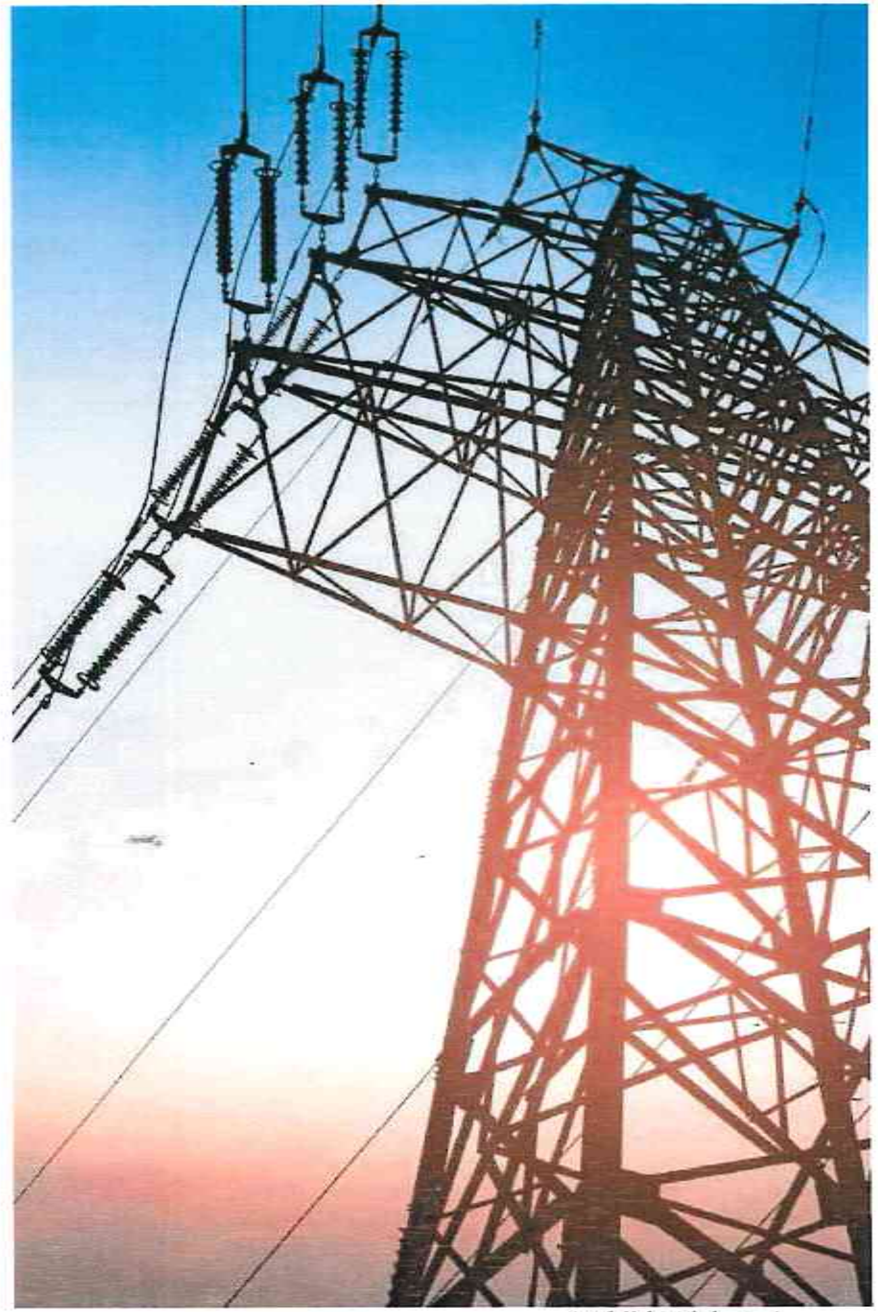

Exhibit Bickett-4

Executive Summary

The electricity sector is undergoing significant and rapid change that presents new challenges and opportunities for reliability. With appropriate insight, careful planning, and continued support, the electricity sector will continue to navigate the associated challenges in a manner that maintains reliability and resilience.

As NERC has identified in recent assessments, retirements of conventional generation and the rapid addition of variable resources, primarily wind and solar, are altering the operating characteristics of the grid in some areas. Natural gas generation is providing the system with increasing flexibility; however, if an area's fuel delivery infrastructure is constrained, a significant influx of natural gas generation raises questions about how disruptions on the natural gas pipeline systems impact electric system reliability.

Distributed energy resources (DERs) and storage are increasingly offering electricity customers an option to reduce energy costs and create additional resilience. By their nature, DERs are increasingly being implemented at the electric distribution level, resulting in a possible net source of power injected into the BPS instead of being load. This change will require a strong transmission system with good links to the distri¬bution system to maintain an appropriate balance between load, variable energy resources (VERs), and energy storage devices.

While risks and corresponding mitigations may be unique to each area, industry stakeholders and policymakers should continue to respond with policies and plans that support a reliable BPS and a strong linkage to the distribution system to enhance the vision of the interactions between the distribution and transmission systems.

This *2019 LTRA* serves as a comprehensive, reliability-focused perspective on the 10-year outlook for the North American BPS and identifies potential risks to inform industry planners and operators, regulators, and policymakers.

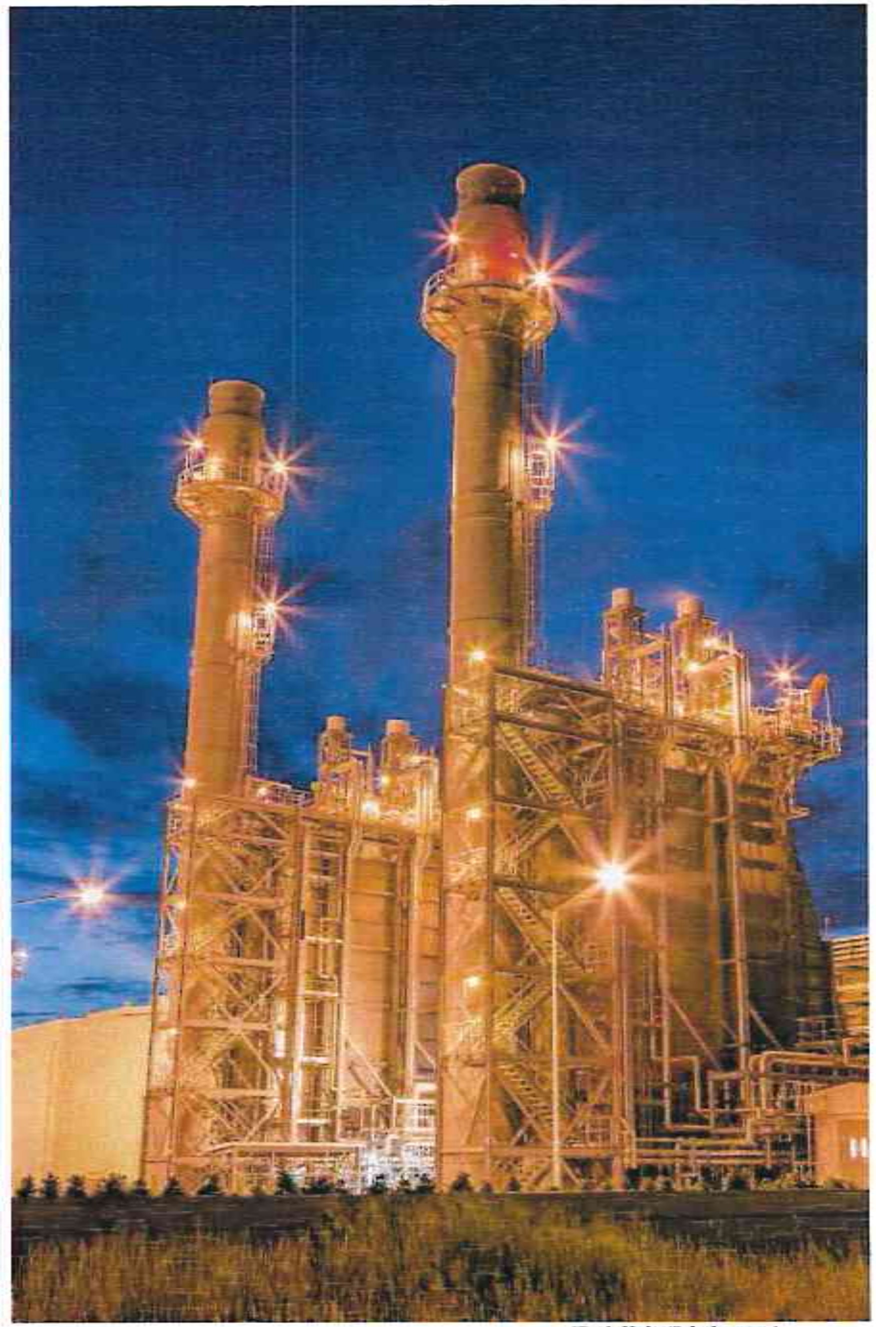

Exhibit Bickett-4

Key Findings

Based on data and information collected for this assessment, NERC has identified four key findings:

Resource Adequacy: Projected reserves fall below the Reference Margin Level in TRE-ERCOT and NPCC-Ontario; there is sufficient generation supply in all other areas:

- The Anticipated Reserve Margin (ARM) in TRE-ERCOT is projected below the Reference Margin Level (RML) in most of the first five-year period, but if additional Tier 2 resources in development come into service, they are more than sufficient to exceed the RML.
- NPCC-Ontario projects a shortfall beginning in 2023 that is driven by nuclear retirements and refurbishments; however, market mechanisms that secure incremental capacity are expected to begin addressing the shortfall in future capacity auctions.
- The emerging risk of energy deficiencies is being identified during off-peak conditions in the Midcontinent Independent System Operator (MISO) area and the Western Electricity Coordinating Council (WECC) Region.
- Sufficient resources are planned to be available throughout the assessment period in all other areas.

Resource Mix Changes: Resource mix changes are driven by the addition of large amounts of new wind, solar, and natural gas resources:

- Some areas of North America have and continue to see more rapid resource mix changes with North America as a whole having a diverse fuel mix.
- Over 330 GW of installed capacity from solar and wind are planned through 2029.
- To accommodate large amounts of solar and wind generation, additional flexible resources are needed to offset ramping and variability.
- Solutions to inverter-based resource interconnection challenges are being implemented to reliably accommodate more resources.
- The growth in natural gas generation requires continued and coordinated planning to maintain appropriate fuel assurance; guidance is currently being developed by the Electric Gas Working Group (EGWG).

Storage and Distributed Energy Resources: Large amounts of storage and distributed energy resources require coordinated interconnection and a robust transmission system:

- A total of 8 GW of BPS-connected electric storage is expected by 2024.
- A total of 35 GW of distributed solar PV is expected by 2024.
- Increasing installations of DERs modify how distribution and transmission systems interact with each other.
- Transmission Planners and Operators may not have complete visibility and control of DERs, but information and data is needed for system planning, forecasting, and modeling as growth becomes considerable.

Transmission Infrastructure: Transmission planning and infrastructure development need to keep pace with an increasing amount of utility scale wind and solar resources:

- Under 15,000 circuit miles of new transmission is expected over the next 6 years; this is considerably less than the nearly 40,000 circuit miles planned earlier this decade.
- Many new VERs will be located in areas remote from demand centers and existing transmission infrastructure. In some areas, such as SPP and ERCOT, the level of VERs are reaching full subscription of the transmission network and exhaust current as well as planned transmission capacity.

Exhibit Bickett-4

Recommendations

Based on the identified key findings, the grid is transforming with the interconnection of new resources with different characteristics and requirements. NERC has formulated the following recommendations, some of which will require the development, validation, and application of new methods, designs, devices, and simulation models:

The ERO should enhance the reliability assessment process by incorporating energy adequacy metrics and evaluating scenarios posing the greatest risk.
The ERO recognizes that the changing resource mix, shifting demands, and other factors can have a significant effect on resource adequacy. As a result, the ERO is incorporating more probabilistic methods and other analysis approaches to provide vital and rich insights to effectively assess reliability of the evolving systems with energy-limited and uncertain resources. While the ERO has historically gauged resource adequacy by using solely planning reserve margins focused at peak demand hour, the ERO will expand its use of probabilistic approaches in the 2020 LTRA to support assessment of resource and energy adequacy across all hours.

The ERO should increase its communication and outreach with state and provincial policymakers on resource adequacy risks and challenges.
As more resources are located on the distribution system, it is important that the ERO effectively communicates resource adequacy risk to its state and provincial stakeholders. The ERO's independent and objective assessment is a valuable resource to regulatory and policy making stakeholders that are ultimately responsible for their jurisdictions' resource adequacy and distribution systems. The changing resource mix creates new technical challenges that are complex and complicated, requiring even greater engagement and outreach. The ERO Enterprise, strengthened by NERC and RE engagement at the state and provincial levels, will amplify and enhance outreach toward providing guidance and information to support continued reliable operation of the BPS.

The ERO should publish reliability guidelines, develop requisite tools, and validate models to establish common industry practices for planning and operating the BPS with increasing energy limitations and disruption risks.
Given the increased reliance on resources that have a higher level of fuel uncertainty than the previous fleet, system planners should identify potential system risks that could occur under extreme but realistic contingencies and under various future supply portfolios. Proper software applications and modeling are required to support system planners performing these studies.

Industry should identify, design, and commit flexible resources needed to meet increasing ramping and variability requirements.
Presently, concerns associated with ramping are largely confined to California. However, as solar generation increases in California and various parts of North America, system planners will need to ensure that sufficient flexibility is available to operators to offset variability and fuel uncertainty.

The ERO and industry need to work together to ensure system studies incorporate DER impacts.
As the penetration of DERs continues to increase across the North American BPS, it is necessary to account for DERs in the planning, operation, and design of the BPS. System operators and planners should gather data as early as possible about the aggregate technical specifications of DERs connected to local distribution grids to ensure accurate and valid system planning device and simulation models, load forecasting, coordinated system protection, and real-time situation awareness. In areas with large or emerging DER penetrations, current operational models and system studies do not properly account for DERs. These models and studies will need to be improved to accurately represent the system's behavior.

The ERO should assess the implications of electricity storage on BPS planning and operations.
Electricity storage has the potential to offer much needed capabilities to the grid of the future. Based on data received in the resource information collected to support this assessment, there will be an increase of BPS-connected storage in the future; this may even be accelerated if the conditions are right. Before this storage is built and integrated into the BPS, the ERO should identify, assess, and report on the risks and potential mitigation approaches to accommodate large amounts of energy storage on BPS reliability.

In future assessments, the ERO should review challenges in transmission development and reliability risks due to the changing resource mix.
To accommodate large amounts of variable generation and to meet policy objectives associated with renewables in a reliable and economic manner, more transmission may be needed. For example, to meet the renewable energy requirements, transmission may be required to ensure that transfer of large amounts of energy can be supported when it becomes available. The ERO should assess and evaluate if the decreasing amount of transmission projects presents any future reliability risks or concerns.

See the Recommendations Tracking Matrix for more information.

Exhibit Bickett-4

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

Adequacy: The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components

Operating Reliability: The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

For adequacy, system operators can and should take controlled actions or introduce procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its load serving entities (LSEs) via contract or agreement for curtailment[5]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

Operating reliability disturbances result in the unplanned and/or uncontrolled interruption of customer demand regardless of cause. When these interruptions are contained within a localized area, the interruptions are considered unplanned interruptions or disturbances. When the interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location. The intent of NERC Reliability Standards is to deliver an adequate level of reliability,[6] which is defined by the following characteristics:

Adequate Level of Reliability: It is the state that the design, planning, and operation of the Bulk Electric System (BES) will achieve when the following reliability performance objectives are met:

- The BES does not experience instability, uncontrolled separation, cascading,[7] and collapse under normal operating conditions and/or voltage when subject to predefined disturbances.[8]
- BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
- BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
- Adverse reliability impacts on the BES following low probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, and malicious acts) are managed.
- Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.
- For rare severe events, BES owners and operators may not be able to apply economically justifiable or practical measures to prevent or mitigate an adverse reliability impact on the BES even if these events can result in cascading, uncontrolled separation, or voltage collapse. Rare severe events include losing an entire right of way due to a tornado, multiple transmission facilities outages due to a hurricane, sizeable disruptions to natural gas infrastructure impacting multiple generation resources, or other severe phenomena.

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5 Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in reliability standards: https://www.nerc.com/files/glossary_of_terms.pdf

6 https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_Technical_Report_clean.pdf

7 NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

8 NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

Exhibit Bickett-4

Detailed Key Findings

Key Finding 1: Projected Reserves Continue to Fall below the Reference Margin Level in TRE-ERCOT, NPCC-Ontario Falls below the RML in 2023, and there Is Sufficient Generation Supply in all other Areas.

Key Points

- The ARM in TRE-ERCOT is projected below the RML) in most of the first five-year period, but if additional Tier 2 resources in development come into service, they are more than sufficient to exceed the RML.
- NPCC-Ontario projects a shortfall beginning in 2023 that is driven by nuclear retirements and refurbishments; however, market mechanisms that secure incremental capacity are expected to begin addressing the shortfall.
- Emerging energy deficiency risks are being identified during off-peak conditions in MISO and WECC.
- Sufficient resources are planned to be available throughout the assessment period in all other areas.

For the majority of the BPS, PRMs appear sufficient to maintain reliability during the long-term, ten-year horizon. However, there are challenges facing the electric industry that may shift industry projections and cause NERC's assessment to change. Where markets exist, signals for new capacity must be effective for planning purposes and reflect the lead times necessary to construct new generation, any requisite natural gas infrastructure, and any associated transmission. Although generating plant construction lead times have been significantly reduced, environmental permitting and pipeline and transmission planning and approval still require significant lead times.[9]

How NERC Evaluates Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the normal projected peak demand and then dividing this difference by the normal projected peak demand. NERC assesses resource adequacy by evaluating each assessment area's PRM relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis.

On the basis of the five-year projected reserves compared to the established RML, as shown in Figure 1, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than RML, and the Prospective Reserve Margin is higher than RML.

Inadequate: The Anticipated and Prospective Reserve Margins are less than the RML, and Tier 3 resources are unlikely to advance.

9 Capacity supply and Planning Reserve Margin projections in this assessment do not necessarily take into account all generator retirements that may occur over the next 10 years or account for all replacement resources explicitly linked with potential retiring resources. While some generation plants have already announced and planned for retirement, there are still many economically vulnerable generation resources that have not determined and/or announced their plans for retirement.

As shown in Figure 1, all assessment areas remain above the Anticipated RML through 2024 with the exception of TRE-ERCOT and NPCC-Ontario.

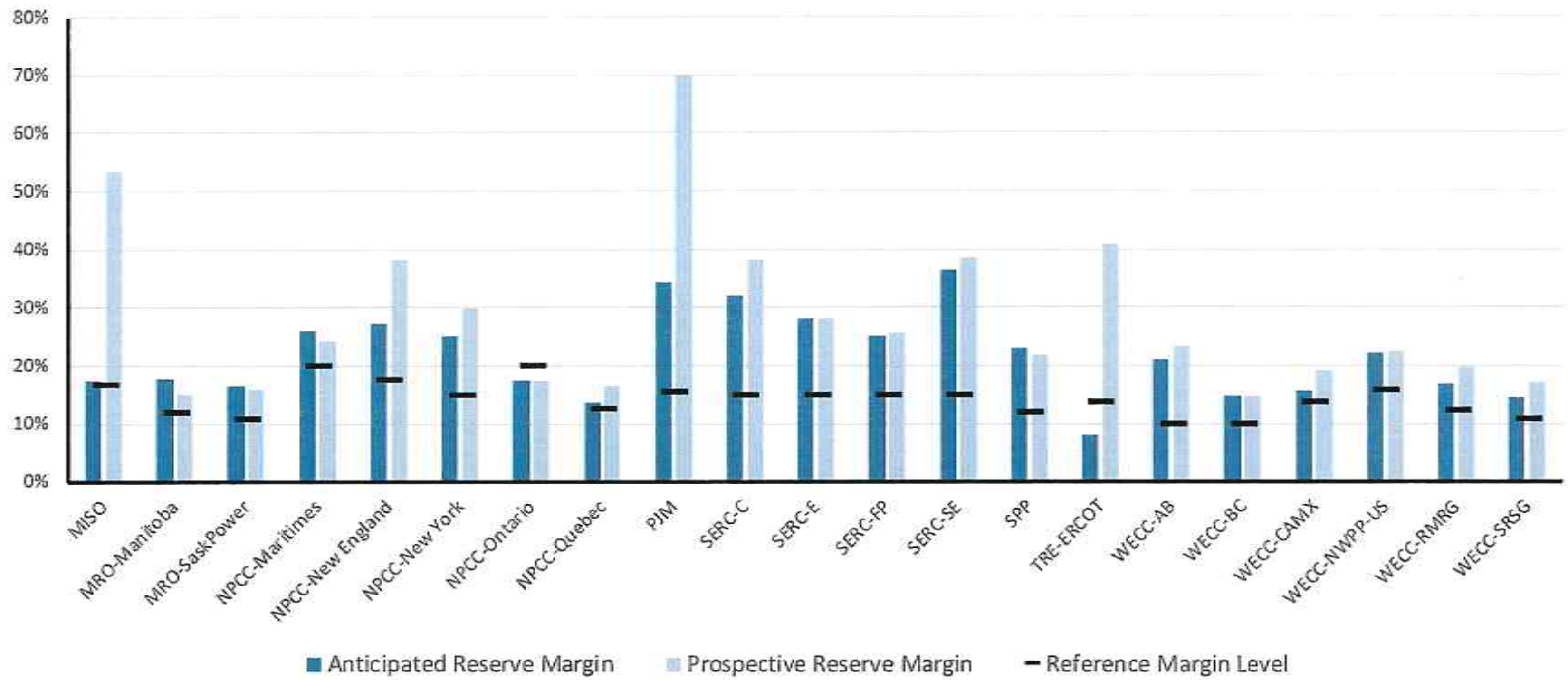


Figure 1: Anticipated and Prospective Reserve Margins for 2024 Peak Season by Assessment Area

The results of NERC's risk determination for all assessment areas is shown in Table 1. NPCC-Ontario and TRE-ERCOT are identified as "Marginal" with all other areas identified as "Adequate" through 2024. While NPCC-Ontario shows only a very small shortfall, TRE-ERCOT shows a shortfall of over 4,000 MW.

Table 1: NERC's Risk Determination of All Assessment Areas 5-Year Projected Reserve Margins

Assessment Area	2024 Peak Anticipated Reserve Margin	2024 Reference Margin Level	Expected Capacity Surplus or Shortfall (MW)	Assessment Result Through 2024
MISO	17.5%	16.8%	877	Adequate
MRO-Manitoba	17.6%	12.0%	269	Adequate
MRO-SaskPower	16.6%	11.0%	219	Adequate
NPCC-Maritimes	26.0%	20.0%	320	Adequate
NPCC-New England	27.3%	17.8%	2,261	Adequate
NPCC-New York	25.3%	15.0%	3,152	Adequate
NPCC-Ontario	17.3%	20.1%	-615	Marginal
NPCC-Quebec	13.7%	12.8%	324	Adequate
PJM	34.3%	15.7%	26,779	Adequate
SERC-C	32.0%	15.0%	3,862	Adequate
SERC-E	28.1%	15.0%	6,828	Adequate
SERC-FP	25.3%	15.0%	4,827	Adequate
SERC-SE	36.5%	15.0%	9,875	Adequate
SPP	23.0%	12.0%	5,966	Adequate
TRE-ERCOT	7.8%	13.75%	-4,859	Marginal
WECC-AB	20.9%	10.1%	1,326	Adequate
WECC-BC	14.8%	10.1%	577	Adequate
WECC-CAMX	15.7%	13.9%	958	Adequate
WECC-NWPP-US	22.1%	15.8%	3,288	Adequate
WECC-RMRG	16.7%	12.4%	590	Adequate
WECC-SRSG	14.5%	11.0%	916	Adequate

NERC Planning Reserve Margin Categories

Anticipated Resources

- **Existing-Certain Generating Capacity:** includes operable capacity expected to be available to serve load during the peak hour with firm transmission
- **Tier 1 Capacity Additions:** includes capacity that is either under construction or has received approved planning requirements
- **Firm Capacity Transfers (Imports Minus Exports):** transfers with firm contracts
- **Confirmed Retirements:** capacity with formalized and approved plans to retire

Prospective Resources

- **Anticipated Resources:** as described above
- **Existing-Other Capacity:** includes operable capacity that could be available to serve load during the peak hour but lacks firm transmission and could be unavailable during the peak for a number of reasons
- **Tier 2 Capacity Additions:** includes capacity that has been requested but approval for planning requirements not received
- **Expected (Nonfirm) Capacity Transfers (Imports Minus Exports):** transfers without firm contracts but a high probability of future implementation
- **Unconfirmed Retirements:** capacity that is expected to retire based on the result of an assessment area generator survey or analysis (This capacity is aggregated by fuel type.)

Planning Reserve Margins in TRE-ERCOT

The projected 5-year ahead ARMs falls below the RML of 13.75% in the first year—Summer 2020, increasing above the RML in 2021 and falling below the RML for the remainder of the LTRA forecast period (Figure 2). The 2020 ARM is projected to be 10.2% and 7.8% by 2024. This is consistent with the findings of the past two LTRAs. The near-term deficiency in the ARM is mainly due to the following:[10]

- An increase in the forecasted summer peak demands, averaging about a 1,300 MW increase from 2019 through 2023
- The mothballing and subsequent retirement of the 470 MW Gibbons Creek coal-fired plant, beginning in October 2018
- Cancellation of two planned natural-gas-fired generation projects with projected 2020 and 2021 in-service dates (combined 1,439 MW summer rating) along with the cancellation of the planned Bethel Compressed Air Energy Storage project (324 MW, projected 2020 in-service date)
- Cancellations of several planned wind projects, totaling over 2,100 MW of installed capacity

ERCOT has a variety of operational tools to help manage tight reserves and maintain system reliability. For example, control room operators can release ancillary services (including load resources that can provide various types of operating reserves depending on meeting certain qualification criteria), deploy contracted emergency response service resources, instruct investor-owned utilities to call on their load management and distribution voltage reduction programs, request emergency power across the dc ties, and request support from available switchable generators currently serving non-ERCOT grids. ERCOT estimates that 2,000–3,000 MW of additional resources will become available when an energy emergency alert is declared.

To respond to such cyclical resource investment and retirement trends, the ERCOT market is designed to incentivize increases in supply along with temporary reductions in demand to maintain the reliability of the system. For example, there are programs operated by ERCOT, retail electric providers, and distribution utilities that compensate customers for reducing their demand or operating their own generation in response to market prices and anticipated capacity scarcity conditions. ERCOT also has operational tools available to maintain system reliability, such as calling upon demand response (DR) resources that are qualified to provide ancillary services, requesting emergency power across the dc ties to neighboring grids, and requesting emergency support from available switchable generators currently serving non-ERCOT grids. However, insufficient reserves during peak hours could lead to an increased risk of entering emergency operating conditions, including the possibility of rotating firm load outages.

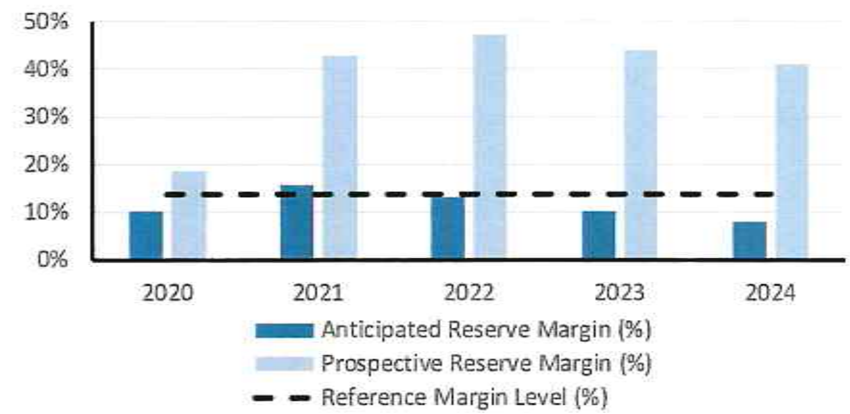


Figure 2: TRE-ERCOT 5-year Projected Reserves (ARM and PRM)

Since 2010, a downward trend in ERCOT's reserve margins has led to scarce resources during the peak and less operating flexibility (Figure 3). To some extent, this is an expected outcome of managing resource adequacy through an energy-only market construct.[11] In Texas, regulators ensure reliability through a mechanism called scarcity pricing, allowing real-time electricity prices to reach as high as $9,000/megawatt hour (MWh) in response to capacity shortage conditions. Instead of guaranteeing revenue to capacity resources through a capacity market, the opportunity of high prices is intended to incentivize generators to build new plants and keep them ready to operate. Recent performance over the last several years has proven the ERCOT market and system

10 Generation interconnection queues in the ERCOT area are continually changing and the pace of queue entry has increased since tight conditions in late Summer 2019. Data used in ERCOT ISO's December 5, 2019, Capacity, Demand and Reserves Report shows a higher future peak reserve range of 18%–13% versus 15%–8% in the LTRA for the years 2021 to 2024. Primary differences between this *2019 LTRA* and the *Capacity, Demand, and Reserves Report* reflect a downward revision to the ERCOT load forecast of approximately 1%–1.5% with a marked increase in utility-scale solar expected in Summer 2021.

11 Energy-only markets pay resources only when they provide energy on a day-to-day basis. Conversely, capacity markets aim to ensure resource adequacy by paying resources to commit capacity for delivery years into the future, in addition to energy payments.

Exhibit Bickett-4

operations to be successful with no load shedding events despite setting a new system-wide peak demand record of 73,308 MW on July 19, 2018, and another record of 74,666 MW on August 12, 2019.

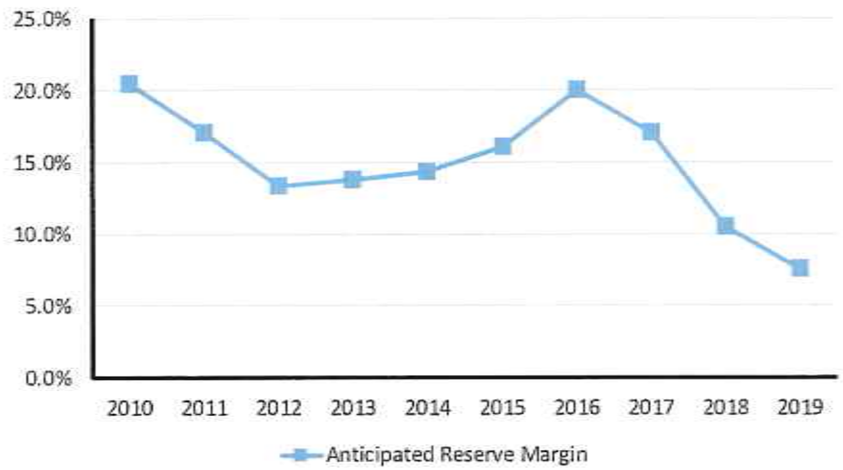


Figure 3: TRE-ERCOT Historical Projected Reserve Margins*

*Projections are Year-1 projections from prior LTRAs. For example, the 2010 value is based on the *2009 LTRA's* 2010 projection.

Planning Reserve Margins in NPCC-Ontario

The ARM falls below the RML to 15% starting in 2023 and 17% in 2024 (Figure 4). This is driven primarily by nuclear retirements and the nuclear refurbishment program. The RML for the summer peak varies over the 10-year period from 19%–26%. Additional reserves are required in 2020 to account for the risk that nuclear refurbishments are not completed on schedule. This risk varies from year-to-year. More reserves are needed when nuclear resources are off-line due to nuclear's high availability compared to the other resources that will need to replace it. The Independent Electricity System Operator's (IESO's) long-term planning forecast anticipates there will be sufficient energy to meet demand and a limited need for new domestic capacity if existing Ontario resources are reacquired when their contracts expire.

The IESO is evolving its capacity market from the existing demand response (DR) auction to a capacity auction. Over the coming years, this auction will allow additional resources to participate, such as off-contract generators. imports, storage, and enhancements of current facilities.

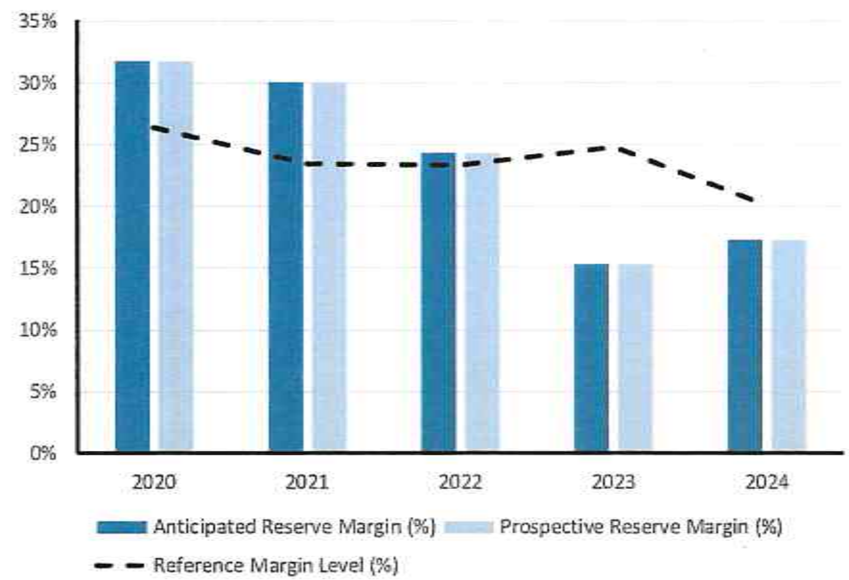


Figure 4: NPCC-Ontario 5-year Projected Reserves (ARM and PRM)

Emerging Reliability Considerations

- **Seasonality of Loss-of-Load Risk:** As the resource mix continues to change, the increase in energy-limited resources and other factors influence resource adequacy. The MISO and WECC-CAMX assessment areas are beginning to see signs of potential energy deficits in the next five years. While traditionally the risk is observed during the summer and winter peak conditions, potential risk is being observed during shoulder and off-peak periods when solar and/or wind output is low.[12] Through periodical probabilistic assessments, the ERO is monitoring the potential for energy deficiencies for all hours.

12 *2018 Long-Term Reliability Assessment*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

Exhibit Bickett-4

- **Potential Implications of Significant Unanticipated Electricity Demand Growth:** A rapid onset of transportation-related or industrial demand could create unexpected load growth. Automobiles are now increasingly battery-powered. Electric heating is also driving efficiency increases as heat pumps replace other forms of heating, including natural gas, oil, and direct electric heating on broader scales.

  Plug-in electric vehicles are projected to account for as much as half of all United States new car sales by 2030. The electricity required to charge these vehicles will increase demand on BPS. Scenario analysis is the best method to understand these potential risks. For example, how might a three-fold increase in electric vehicle penetration by 2028 affect the reliability of the BPS? Would there be a change in planning and/or operating reserve requirements? Would charging patterns affect ramping needs?

Recommendations

The ERO should enhance the reliability assessment process by incorporating energy adequacy metrics and evaluating scenarios posing the greatest risk.
The ERO recognizes that the changing resource mix, shifting demands, and other factors can have a significant effect on resource adequacy. As a result, the ERO is incorporating more probabilistic methods and other analysis approaches to provide vital and rich insights to effectively assess reliability of the evolving systems with energy-limited and uncertain resources. While the ERO has historically gauged resource adequacy by using solely planning reserve margins focused at peak demand hour, the ERO will expand its use of probabilistic approaches in the 2020 LTRA to support assessment of resource and energy adequacy across all hours.

The ERO should increase its communication and outreach with state and provincial policymakers on resource adequacy risks and challenges.
As more resources are located on the distribution system, it is important that the ERO effectively communicates resource adequacy risk to its state and provincial stakeholders. The ERO's independent and objective assessment is a valuable resource to regulatory and policy making stakeholders that are ultimately responsible for their jurisdictions' resource adequacy and distribution systems. The changing resource mix creates new technical challenges that are complex and complicated, requiring even greater engagement and outreach. The ERO Enterprise, strengthened by NERC and RE engagement at the state and provincial levels, will amplify and enhance outreach toward providing guidance and information to support continued reliable operation of the BPS.

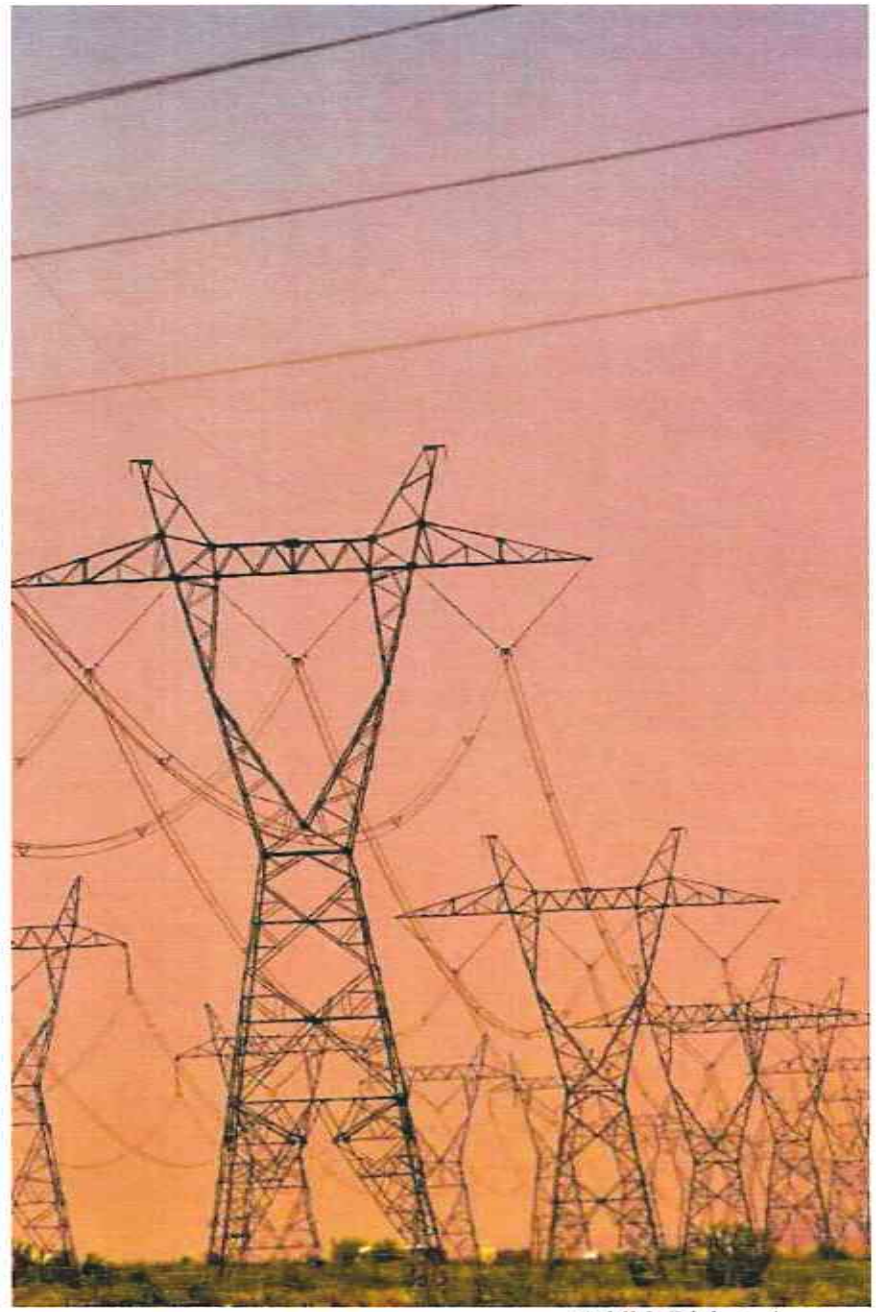


Exhibit Bickett-4

Key Finding 2: Resource Mix Changes Driven by the Addition of Large Amounts of New Wind, Solar, and Natural Gas Resources.

Key Points

- While some areas of North America have and continue to see more rapid resource mix changes, North America has a diverse fuel mix and modest changes are currently planned over the 10-year period as a whole.
- Over 330 GW of installed capacity from solar and wind are planned through 2029.
- To accommodate large amounts of solar and wind generation, additional flexible resources are needed to offset ramping and variability.
- Solutions to inverter and protection challenges are being implemented to reliably accommodate more resources.
- The growth in natural gas generation requires continued and coordinated planning to maintain appropriate fuel assurance; guidance is currently being developed by the EGWG.

Fuel Mix Changes

Figure 5 identifies the components of the fuel mix for the United States and Canada as a whole. From an installed capacity perspective, wind and solar resources have the largest impact to the North American generation fleet with a combined increase from 15% in 2019 to 26% by 2029. Coal and nuclear are projected to decrease from 20% and 9%–16% and 7%, respectively. Included in the "Other" category is battery storage, among other forms of generation.

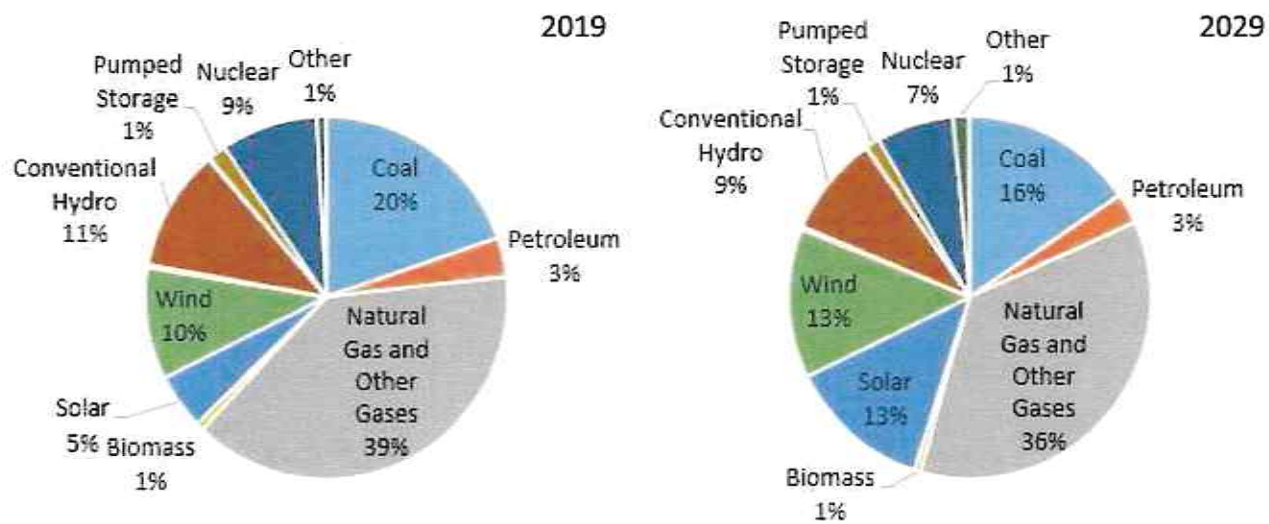


Figure 5: Installed Nameplate Capacity by Fuel Mix Trend (Includes Future Tier 1 Resources)

Figure 6 shows the installed capacity composition of generating resources NERC-wide as of July 2019 compared to the projected installed capacity composition of 2029 (includes Tier 1 additions). Installed nameplate capacity suggests what resource is capable of producing at its maximum potential output. Notably, wind and solar increase from a combined 10–a combined 16%.

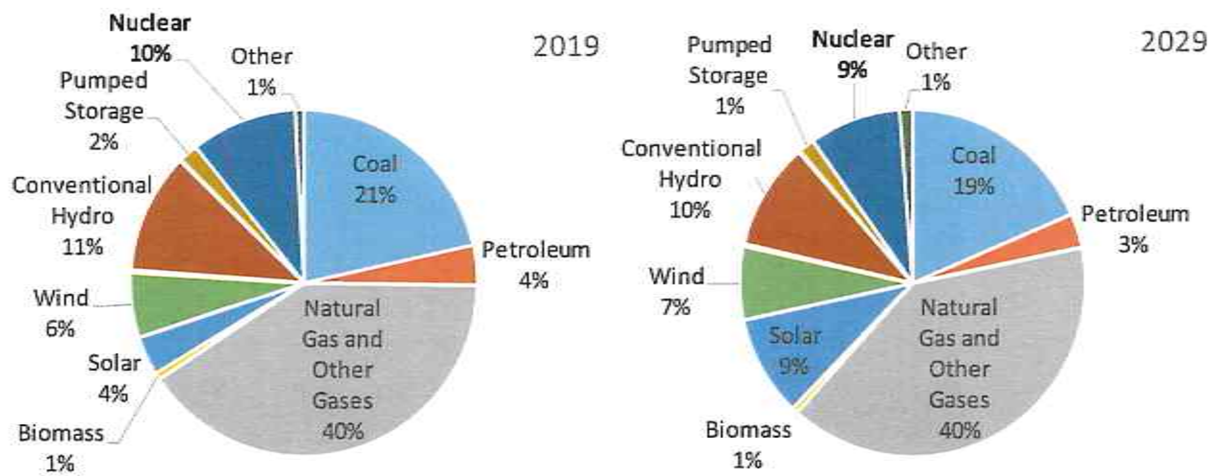


Figure 6: Installed On-Peak Anticipated Capacity Trend by Fuel Mix

NERC Capacity Supply Categories

Future capacity additions are reported in three categories:

Tier 1: Planned capacity that meets at least one of the following requirements are included as anticipated resources:

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection service agreement
- Signed/approved power purchase agreement
- Signed/approved Interconnection construction service agreement
- Signed/approved wholesale market participant agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to vertically integrated entities)

Tier 2: Planned capacity that meets at least one of the following requirements are included as prospective resources:

- Signed/approved completion of a feasibility study
- Signed/approved completion of a system impact study
- Signed/approved completion of a facilities study
- Requested Interconnection service agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to regional transmission organizations (RTOs)/ISOs)

Tier 3: Tier 3 is other planned capacity that does not meet any of the above requirements.

Figure 7 shows the on peak capacity composition of generating resources NERC-wide as of July 2019 compared to the projected on peak capacity composition of 2029 (includes Tier 1 additions). On-peak capacity gives an idea of what a resource is capable of producing at peak demand. Notably, wind and solar increase from a combined 10–a combined 16%.

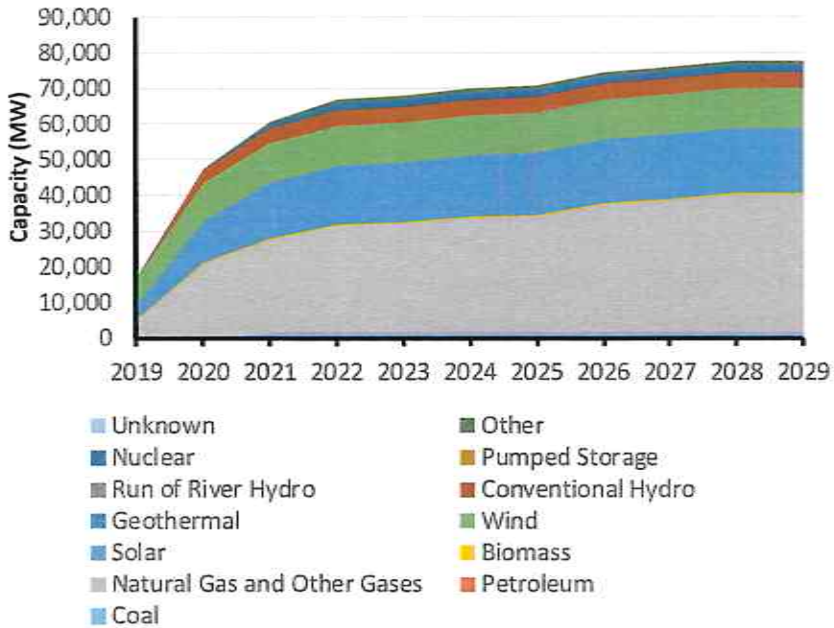


Figure 7: Tier 1 Planned Resources Projected Through 2029

In addition to natural-gas-fired generation, solar additions provide the second most additions to capacity to the overall North American fuel mix with approximately 18 GW of Tier 1 capacity (Figure 7). Tier 1 wind additions total to almost 11 GW of capacity. When considering Tier 2 resources, up to 88 GW of solar and 27 GW of wind are projected (Figure 8). These projections are used for peak reserve margin purposes and are different than the solar resource nameplate capacity.[13]

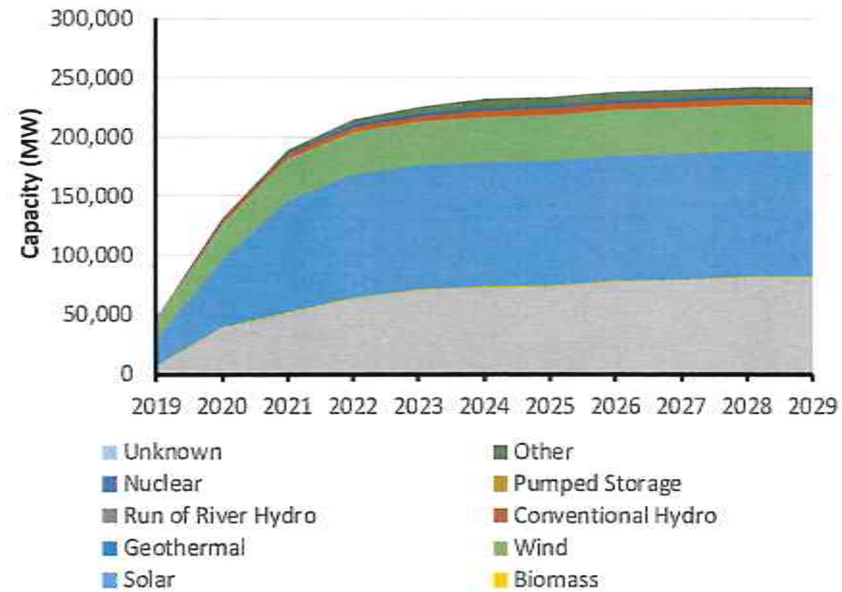


Figure 8: Tier 1 and 2 Planned Resources Projected Through 2029

While some areas of North America have and continue to see more rapid resource mix changes, North America has a diverse fuel mix and modest changes are currently planned over the 10-year period as a whole. A 10-year projection of North America peak capacity is shown in Figure 9. The changes level off around 2024 as the majority of planning occurs five years in advance.

Figure 10 shows the net change of generating capacity since 2012 and the planned retirements for the forward looking 10-year period. Coal and petroleum both have negative net changes, an indication that coal and petroleum are being phased out in favor of other resources. The capacity of coal and petroleum is reduced by 35 GW and almost 4 GW, respectively, since 2012. During the same period, natural gas increased by almost 130 GW.

13 The nameplate capacity additions for 2028 are 18 GW of Tier 1 capacity and 86 GW of Tier 2 capacity.

Exhibit Bickett-4

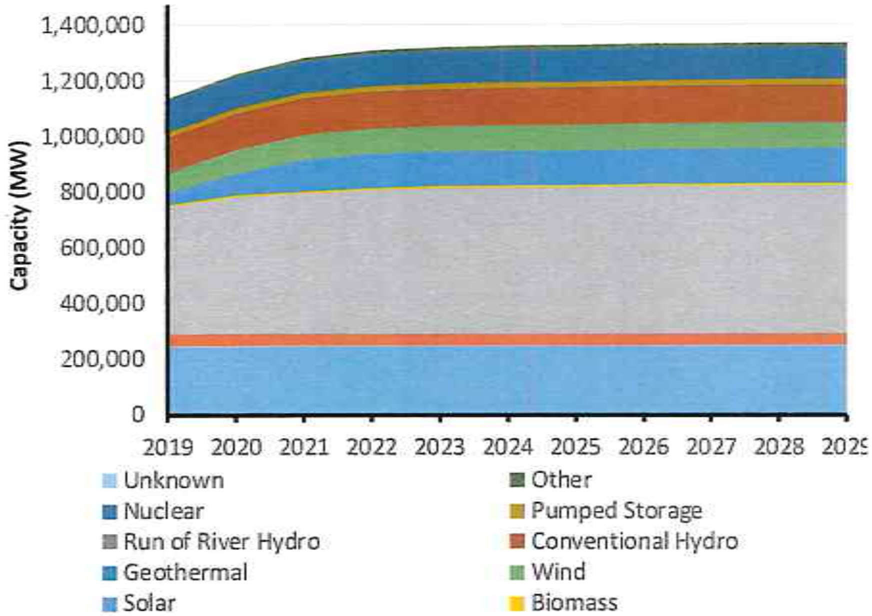


Figure 9: Existing, Tier 1, and 2 Planned Resources Projected through 2029

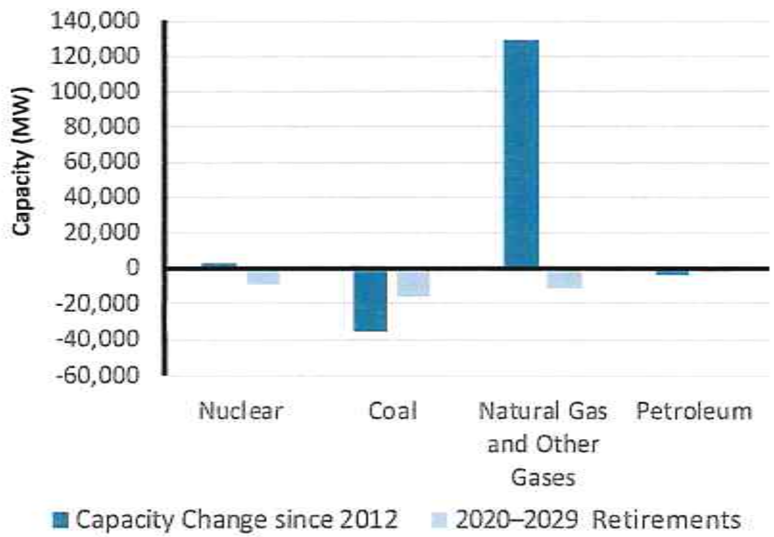


Figure 10: Capacity Changes since 2012 and Retirements Projected through 2029

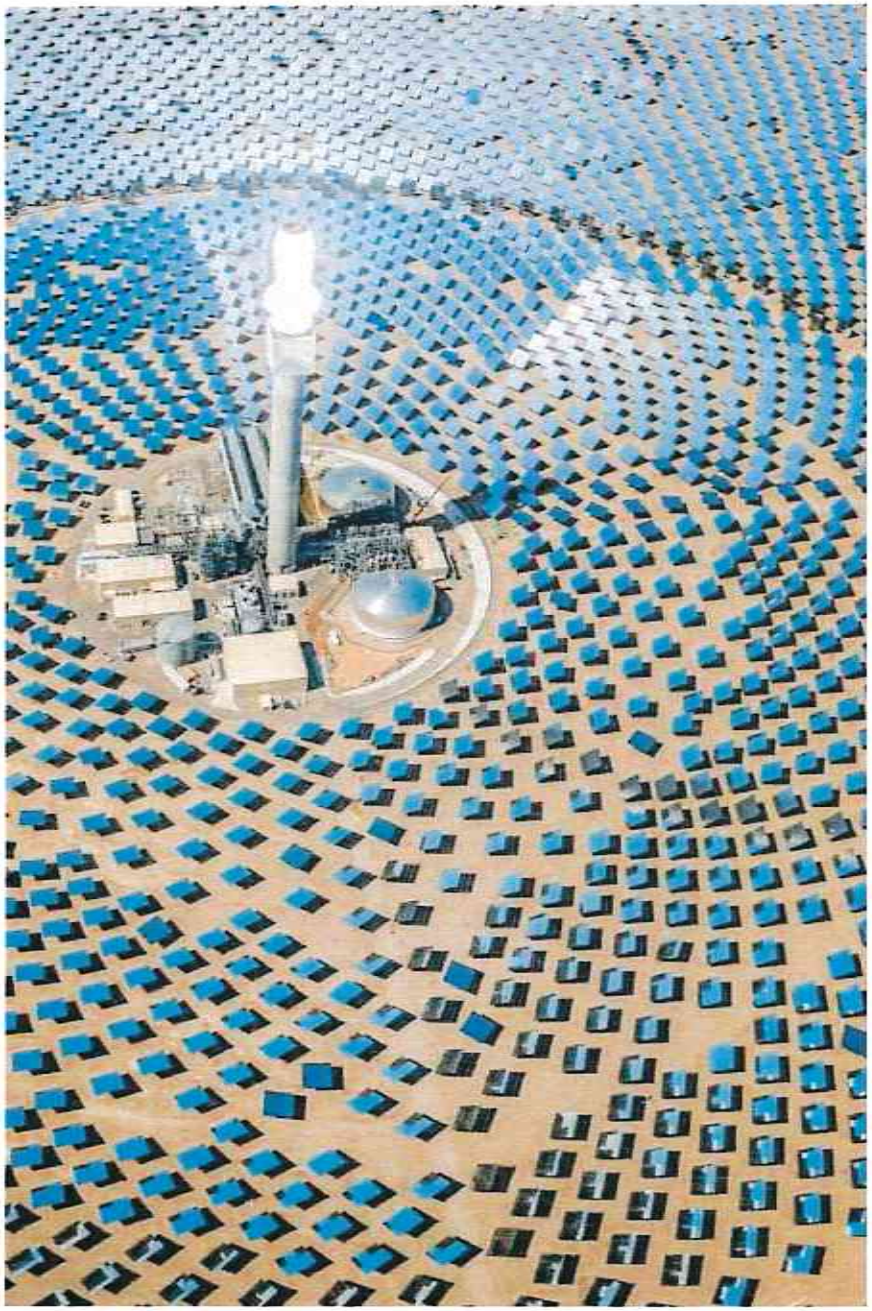
Operating Reliability Risks Due to Conventional Generation Retirements

Capacity retirements located near metropolitan areas or large load centers that have limited transmission import capability present the greatest potential risk to reliability. Unless these retirements are replaced with plants in the same vicinity, these load centers will require increased power imports and dynamic reactive resource replacement.[14] If the transmission links between an area and generation sources are relatively weak, voltage instability can be the result; dynamic reactive power must be provided to prevent voltage collapse. Solutions to preventing voltage instability could range from extensive transmission improvements to optimal placement of static VAR compensators, synchronous condensers, locating new generation in the load pocket, or local energy storage. Retiring generation units in a generation "pocket" might cause the remaining units to become "reliability must run" units that often require additional actions or investments (e.g., transformers, shunt capacitors) in equipment to maintain voltage stability.

Figure 11 displays the capacity retirements for the previous 7-year period as well as the 10-year projected cumulative retirements through 2029. Between the years 2012 and 2018, over 32 GW of coal generation and over 7 GW of natural gas generation were retired among the almost 43 GW retired in that period of time. The cumulative projected retirements for the 10-year period of 2019–2029 are forecasted to exceed 46 GW in capacity. All of the projected nuclear retirements for the 10-year period occur by 2024, totaling over 10 GW of capacity. The other projected retirements mostly consist of 19 GW of coal and 13.5 GW of natural gas. The 10-year projected retirements are based on committed retirements known to date and is expected to increase as the time horizon progresses.

14 Dynamic reactive support is measured as the difference between its present VAR output and its maximum VAR output. Dynamic reactive support is used to support system state transients occurring post-contingency. NERC's *Reactive Power Planning Reliability Guideline* provides strategies and recommended practices for reactive power planning and voltage control and accounts for operational aspects of maintaining reliable voltages and sufficient reactive power capability on the BPS: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Reactive%20Power%20Planning.pdf

Exhibit Bickett-4



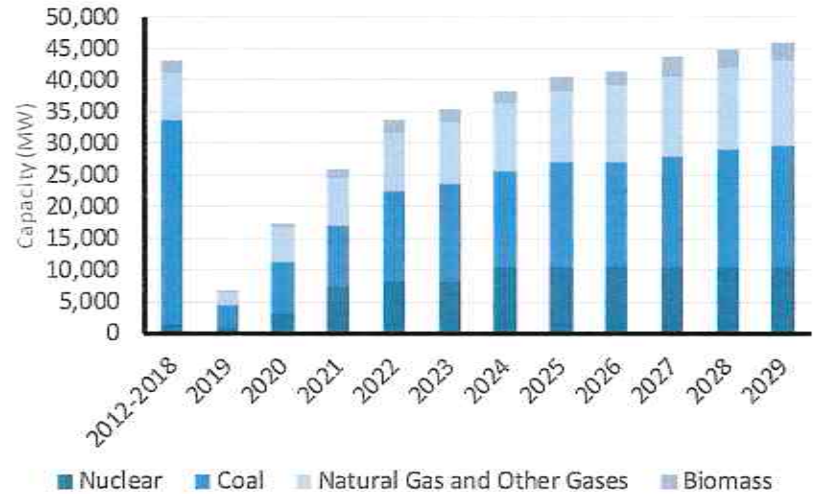


Figure 11: Nameplate Capacity Retirements since 2012 and Projected Cumulative Retirements through 2029

Solar and Wind Capacity Additions

Significant solar and wind capacity additions are expected over the next 10 years. Table 2 identifies solar and wind installed capacity additions by assessment area. From an installed capacity perspective, over 335 GW of new solar and wind are planned through 2029, including Tier 1, 2, and 3 resources. Of all generation resources, future solar capacity is expected to be the largest contribution at 160 GW when considering Tier 1 and 2 resources and 206 GW when considering Tier 3 resources. Wind capacity is expected to more than double by 2029, and over 100 GW are planned when considering Tier 1 and 2 resources.

Exhibit Bickett-4

Table 2: Solar and Wind Installed Capacity, Existing and Planned Additions through 2029

	Nameplate Capacity of Solar (MW)					Nameplate Capacity of Wind (MW)				
Assessment Area	**Existing**	**Tier 1**	**Tier 2**	**Tier 3**	**Total**	**Existing**	**Tier 1**	**Tier 2**	**Tier 3**	**Total**
MISO	280	2,040	60,125	640	**63,084**	19,172	7,598	27,468	5,714	**59,953**
MRO-Manitoba	0	0	0	0	**0**	259	0	0	0	**259**
MRO-SaskPower	0	10	20	50	**80**	242	377	0	400	**1,019**
NPCC-Maritimes	1	3	0	0	**4**	1,146	80	0	30	**1,256**
NPCC-New England	1,206	126	509	2,555	**4,396**	1,390	111	4,884	5,963	**12,348**
NPCC-New York	32	20	0	686	**738**	1,898	226	1,091	3,350	**6,565**
NPCC-Ontario	424	54	0	0	**478**	4,431	460	0	0	**4,891**
NPCC-Quebec	0	0	0	0	**0**	3,776	54	0	0	**3,830**
PJM	1,549	3,915	41,754	0	**47,219**	8,012	3,419	22,538	0	**33,969**
SERC-C	10	268	597	3,758	**4,633**	486	0	0	0	**486**
SERC-E	491	0	0	0	**491**	0	0	0	0	**0**
SERC-FP	1,121	8,855	0	0	**9,976**	0	0	0	0	**0**
SERC-SE	1,248	893	705	2,188	**5,034**	0	0	0	0	**0**
SPP	276	0	650	25,307	**26,233**	20,486	300	2,500	31,905	**55,191**
TRE-ERCOT	1,857	7,699	27,376	26,155	**63,087**	22,090	14,457	15,191	5,864	**57,602**
WECC-AB	0	0	0	900	**900**	0	0	0	4,400	**4,400**
WECC-BC	1	1	21	79	**102**	702	26	0	184	**912**
WECC-CAMX	11,784	0	475	6,051	**18,310**	6,191	0	469	1,144	**7,804**
WECC-NWPP-US	2,479	3,352	39	0	**5,869**	9,764	1,134	504	0	**11,402**
WECC-RMRG	464	292	720	45	**1,521**	3,792	59	969	354	**5,175**
WECC-SRSG	1,399	301	167	2,807	**4,673**	1,162	165	99	776	**2,202**
Total	**24,620**	**27,828**	**132,508**	**45,914**	**230,870**	**104,998**	**27,789**	**73,213**	**28,179**	**234,179**

Exhibit Bickett-4

Figure 12 shows the planned solar capacity for assessment areas through 2029. MISO, PJM, and TRE-ERCOT have the most total planned, mostly Tier 2 resources. SPP contains almost 26 GW of planned solar capacity, mostly Tier 3 resources. WECC-CAMX leads the way with over 11 GW of current solar capacity, the most currently installed.

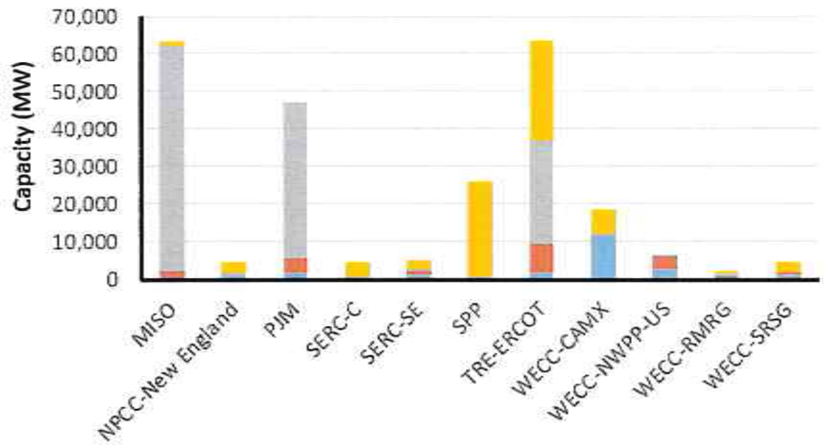


Figure 12: Solar Nameplate Capacity Planned and Existing

Figure 13 shows the planned wind capacity for assessment areas through 2029. As with solar, the larger footprint assessment areas of MISO, PJM, SPP, and TRE-ERCOT have the most total planned. MISO, SPP, and TRE-ERCOT are all about 20 GW of currently installed wind capacity, the only assessment areas with above 10 GW of installed wind capacity thus far.

Natural Gas Capacity Additions

NERC-wide natural-gas-fired on-peak generation has increased from 280 GW in 2009 to 460 GW today with an additional 43 GW planned during the next decade—88 GW when considering Tier 2 additions as shown in Figure 14.

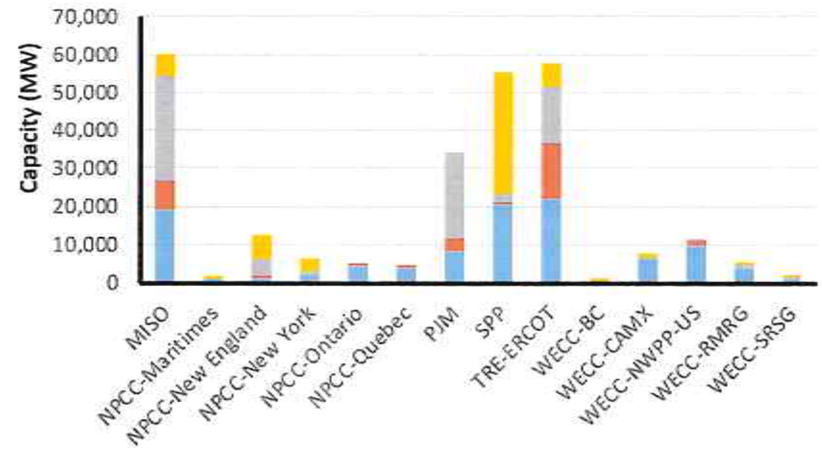


Figure 13: Wind Nameplate Capacity Planned and Existing

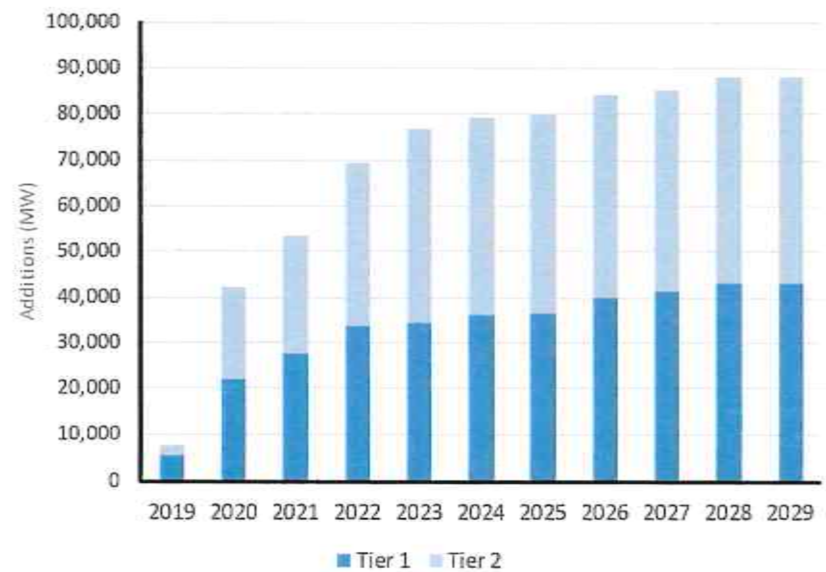
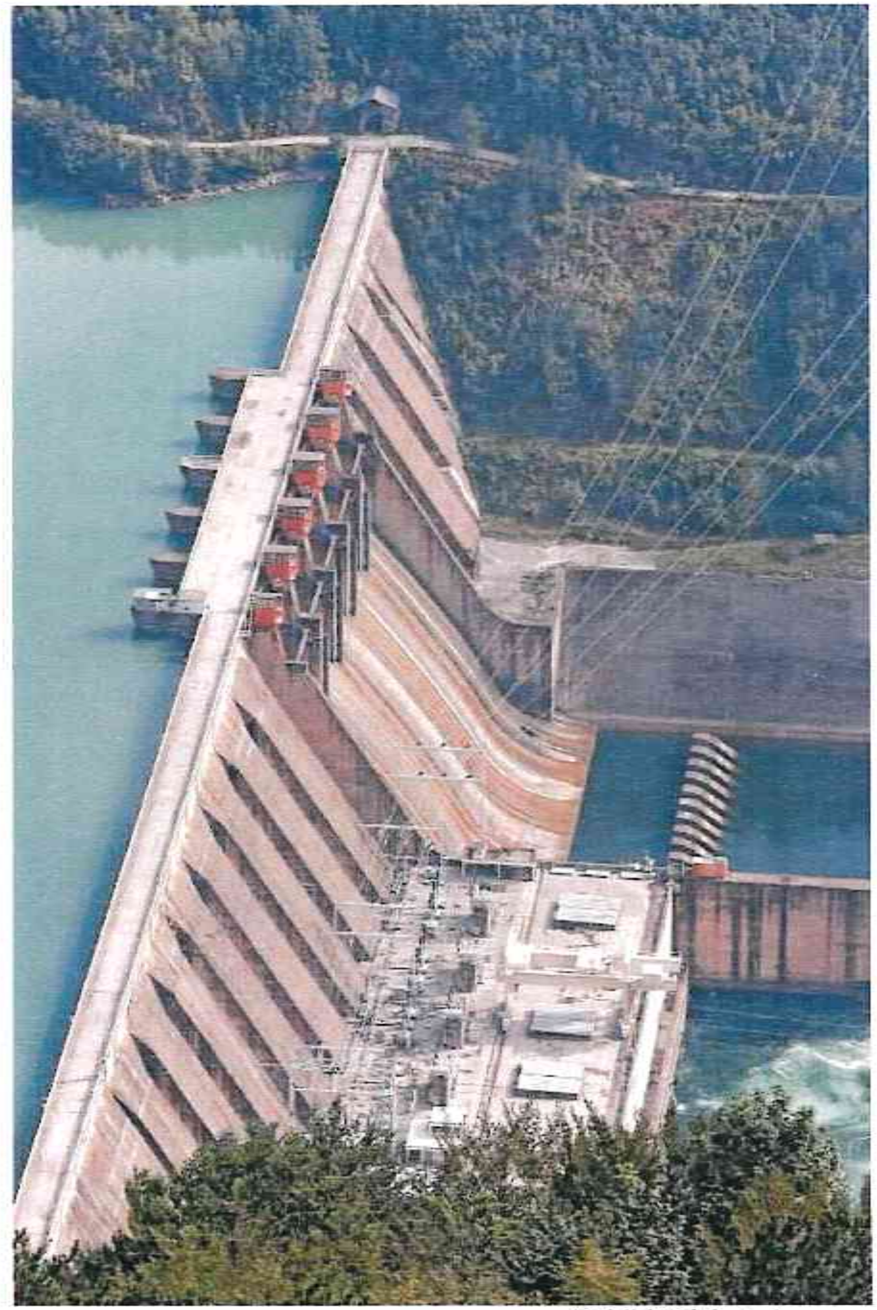


Figure 14: Natural Gas Capacity Planned Additions through 2029, Tier 1 and 2

Exhibit Bickett-4

Unlike other conventional generation with on-site storage, natural gas generation uses the natural gas pipeline system to receive just-in-time fuel to burn for electricity production. Pipeline transportation service is subject to interruption and curtailment depending on the generator's level of service. In constrained natural gas markets, generation without firm transportation may not be served during peak pipeline conditions, and arrangements for alternative fuels should be considered. Some plants no longer have the option of burning a liquid fuel. Further, regardless of fuel service arrangements, natural gas generation is subject to curtailment during a force majeure event.

In November 2017, NERC published the *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*.[15] In the report, NERC made numerous recommendations for assessing disruptions to natural gas infrastructure and related impacts to the reliable operation of the BPS in planning studies. The EGWG[16] was created to gather industry experts and drive the development of tools and other resources to better educate and inform the electric industry about how to reduce risks related to the disruption of fuel supplies.



15 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

16 https://www.nerc.com/comm/PC/ElectricGas%20Working%20Group%20EGWG/EGWG%20Scope%20Document%20-%20May%202019.pdf

Exhibit Bickett-4

Maintaining Fuel Assurance

Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural gas and limited pipeline infrastructure. Fuel assurance, while not explicitly defined, refers to the confidence system planners have in a given resource's availability based on its fuel limitations. In some areas, natural gas delivery pipelines were built and sized to serve customers of natural gas utilities—not specifically to serve electricity generators. Higher reliance on natural gas can lead to fuel-security issues, particularly during extreme cold weather periods when demand on the natural gas delivery system can be stressed, exposing electric generation to fuel supply and delivery vulnerabilities.

Mechanisms that Promote Fuel Assurance	Planning Considerations
Fuel Service Agreements	• Service level arrangements should be considered in resource adequacy planning. • In areas with constrained natural gas pipeline infrastructure, generators with firm fuel service are likely to be available more often than those with interruptible service. • Generators that have procured firm service on a secondary market may be interrupted prematurely. • Firm service does not guarantee delivery if a force majeure is in effect.
Alternative Fuel Capabilities	• Dual-fuel firing capability and seasonal inventories should be considered in capacity and energy adequacy planning. • Generators with dual fuel capabilities are likely to have greater availability than those without. • Backup fuel inventory must be maintained in order for dual fuel capabilities to promote fuel assurance.
Pipeline Connections	• More pipeline connections from different sources can increase the resilience of a plant's fuel supply. • Greater fuel assurance can be reached if multiple fuel supply sources and transportation paths are used to supply a given generator.
Market and Regulatory Rules	• Market and other state, federal, and provincial rules, incentives, and penalties can be used to compel Generator Owners to perform in a manner that promotes reliability, resilience, and fuel assurance. • Regulatory policies can help attract greater access and installation of fuel supplies, including resilience in pipeline transportation.
Vulnerability to Disruptions	• Geography and access to natural resources can impact a given area's vulnerability to disruption. • Areas at the "end of the line" will likely have an overall greater risk profile than those in close proximity to fuel supply sources. • Areas relying on liquefied natural gas (LNG) are vulnerable to fuel supply and delivery disruptions that are very different to pipeline vulnerabilities, including political unrest and global prices.
Pipeline Expansions	• Areas that have an increasing amount of transportation capacity being added may be reducing their risk. • Pipeline expansion into constrained areas significantly promotes fuel assurance.

New England is currently fuel constrained; this has been identified as one of the most significant risks to the area. Output restrictions at dual-fuel plants due to air emission regulations also contribute to this risk. With its existing fuel infrastructure, New England has faced challenging operating conditions, particularly in extreme cold weather. Given the shift in the current resource mix, these challenges are likely to extend beyond the winter season. During extreme cold periods, electricity needs have been met through a combination of generators using natural gas from pipelines and LNG and the now-declining nuclear, coal, and oil-fired generators. Although new, incremental natural-gas-fired generation is being added to the fuel mix, the regional natural gas pipelines continue to have limited fuel deliverability for any power generators without firm natural gas transportation contracts. Additionally, LNG deliveries to New England that are influenced by global economics and logistics can also be uncertain without firm supply contracts. Environmental permitting for new dual-fuel capability (typically, natural gas and fuel oil) is becoming more difficult under ever tightening state and federal air emissions regulations. Even when these units are granted permits, their run times for burning fuel oil are usually restricted to limit their ozone season (i.e., May 1–September 30) air emissions. Figure 15 shows that natural gas demand will continue to increase with no pipeline additions projected in the near future.

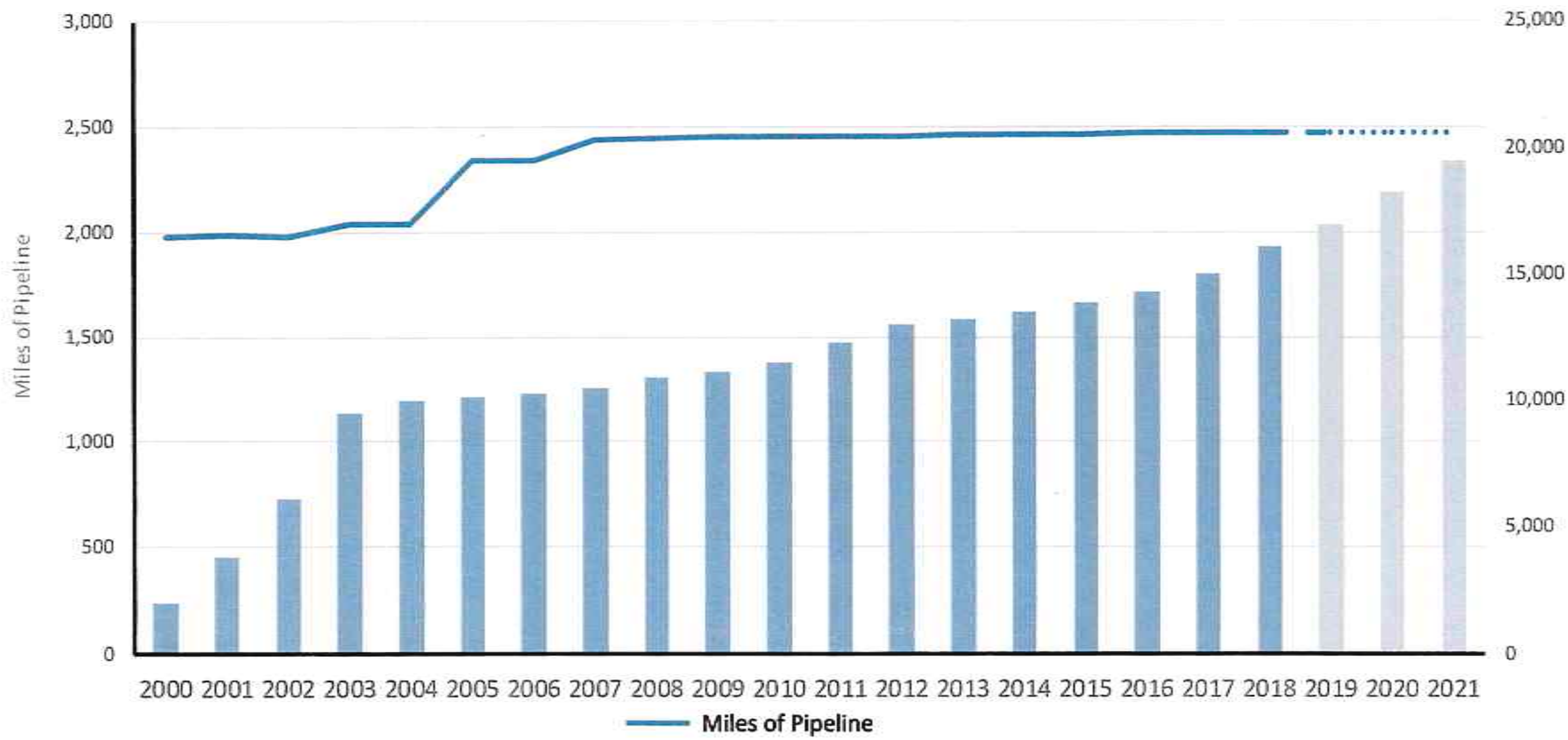


Figure 15: Natural Gas Generation Expansion in New England Compared to Interstate Pipeline Miles

Exhibit Bickett-4

Giving heightened priority to the regional energy security issue, the Federal Energy Regulatory Commission (FERC) directed ISO New England to submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns" in 2018.[17] That directive arose amidst a contentious regulatory process involving shorter-term, out-of-market actions to bolster the area's (winter) fuel supplies by delaying the retirement of the large Mystic Generating Station in Everett, Massachusetts. This station is fueled solely by vaporized LNG from the Distrigas LNG Import Terminal located on the Mystic River, also in Everett, MA.

Figure 16 shows the assessment areas with solar and wind resources over 5% of their peak demand for the years 2019, 2024, or both. The percentages located beside each bar indicate that two assessment areas have to rely on these resources to meet peak demand as their peak demand exceeds the total capacity of conventional resources. WECC-CAMX and TRE-ERCOT are becoming increasingly reliant on solar and wind resources to meet peak demand. In the event solar and wind output is below expectations, CAMX and TRE-ERCOT may need to rely on additional and/or external resources to cover the shortfall.

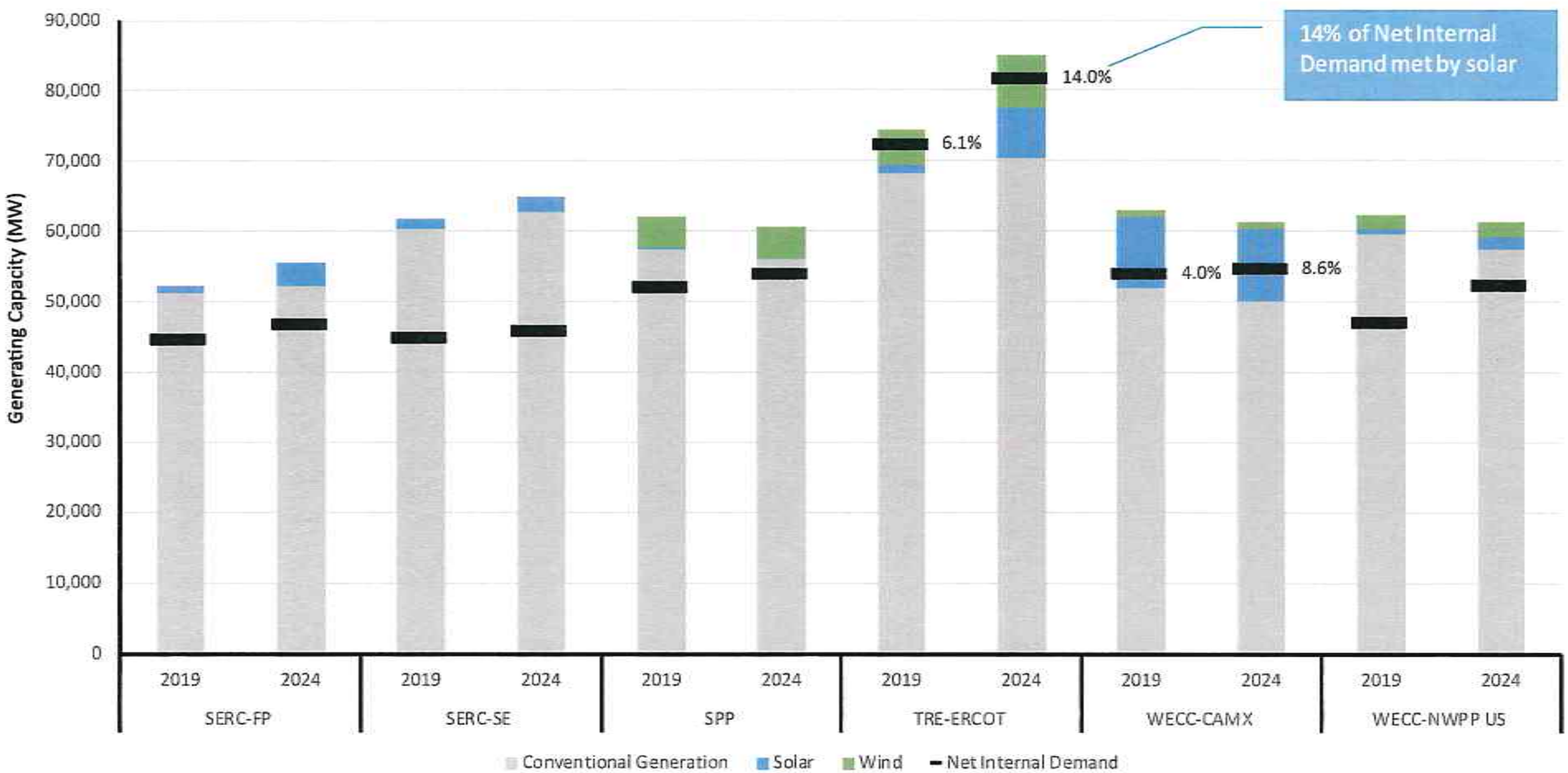


Figure 16: Assessment Areas with Solar and Wind Capacity Greater than 5% of On-Peak Demand

17 ISO New England Inc., 164 FERC ¶ 61,003 at PP 2, 5 (2018).

Exhibit Bickett-4

Emerging Reliability Considerations

Replacing coal and nuclear generation with nonsynchronous and natural-gas-fired generation introduces new considerations for reliability planning, such as ensuring there is adequate inertia, ramping capability, frequency response, and fuel assurance on the system. NERC data and analysis indicate that inertia and frequency response are adequate for all Interconnections and generally trending in a positive direction. This data shows that ERCOT's frequency response is highest when wind output is high.[18] Specific emerging reliability considerations include the following:

- **Planning for Increased Natural Gas Dependency:** During the past decade, several assessment areas have significantly increased dependence on natural-gas-fired generation. As natural-gas-fired generation continues to increase, vulnerabilities associated with the natural gas pipeline system can potentially result in greater electric generation outages. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electric reliability. Disruptions to the fuel delivery results from adverse events that may occur, such as line breaks, well freeze-offs, or storage facility outages. The pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor-driven compressors) that are compounded when multiple plants are connected through the same pipeline or storage facility. Although the ability to use alternate fuel provides a key mitigation effect, only 27% of natural-gas-fired capacity added in the United States since 1997 is dual fuel capable.
- **Increasing Need for System Flexibility:** In order to maintain load-and-supply balance in real time with higher penetrations of variable supply and less-predictable demand, operators are seeing the need to have more system ramping capability. As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability—such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within their committed portfolios or by removing system constraints to flexibility.[19] In particular, the following areas are currently impacted the most:
    - **California:** Increasing solar generation increases the need for flexible resources. CAISO's 2020 solar generation projection increases the three-hour ramp requirement to over 18,500 MW, approximately 8% greater than the amount projected for 2019. The requirement further increases to over 20,000 MW by 2022.[20]
    - **Texas:** Changing ramping requirements induced by increasing amounts of wind is largely managed with improved forecasting. Ramp forecasts allow ERCOT operators to curtail wind production and/or reconfigure the system in response to large changes in wind output.

Recommendations

The ERO should publish reliability guidelines, develop requisite tools, and validate models to establish common industry practices for planning and operating the BPS with increasing energy limitations and disruption risks.

Given the increased reliance on resources that have a higher level of fuel uncertainty than the previous fleet, system planners should identify potential system risks that could occur under extreme but realistic contingencies and under various future supply portfolios. Proper software applications and modeling are required to support system planners performing these studies.

Industry should identify, design, and commit flexible resources needed to meet increasing ramping and variability requirements.

Presently, concerns associated with ramping are largely confined to California. However, as solar generation increases in California and various parts of North America, system planners will need to ensure that sufficient flexibility is available to operators to offset variability and fuel uncertainty.

18 *2019 State of Reliability Report*: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2019.pdf

19 https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS_Measure_6_Forward_Tech_Brief_03292018_Final.pdf

20 https://www.caiso.com/Documents/2019FinalFlexibleCapacityNeedsAssessment.pdf

Exhibit Bickett-4

Key Finding 3: Large Amounts of Storage and Distributed Energy Resources Require Coordinated Interconnection and Robust Transmission System.

Key Points

- A total of 8 GW of BPS-connected electric storage is expected by 2024.
- A total of 35 GW of distributed solar photovoltaic (PV) is expected by 2024.
- Increasing installations of DERs modify how distribution and transmission systems interact with each other.
- Transmission Planners and Operators may not have complete visibility and control of DERs, but information and data is needed for system planning, forecasting, and modeling as growth becomes considerable.

The generation mix is undergoing a transition from large, synchronously connected generators to smaller natural-gas-fired generators, renewable energy, and DR. The growing interest in a more decentralized electric grid and new types of distributed resources further increases the variety of market stakeholders and technologies, including a variety of electric storage. Both new and conventional stakeholders are building or planning to build distributed solar PV systems, energy management systems, microgrids, demand services, aggregated generation behind the retail meter, and many other types of distributed generation. Many of these stakeholders have considerable experience with installing such systems on the distribution network for the benefit of industrial or residential customers but may have less familiarity with the BPS and the coordinated activities that ensure system reliability during both normal operation and in response to disturbances.

At low penetration levels, the effects of DERs may not present a risk to BPS reliability. However, as penetrations increase, the effect of these resources can present certain reliability challenges that require attention. This leads to areas where further consideration is needed to better understand the impacts and how those effects can be included in planning and operations of the BPS. A recent NERC report, *Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*,[21] provides a detailed assessment of DERs and their potential impact on BPS reliability.

Projection of Distributed Energy Resources

Figure 17 shows the amount of DERs NERC-wide through 2029. The amount of DERs is projected to more than double by 2029, surpassing 45 GW total capacity.

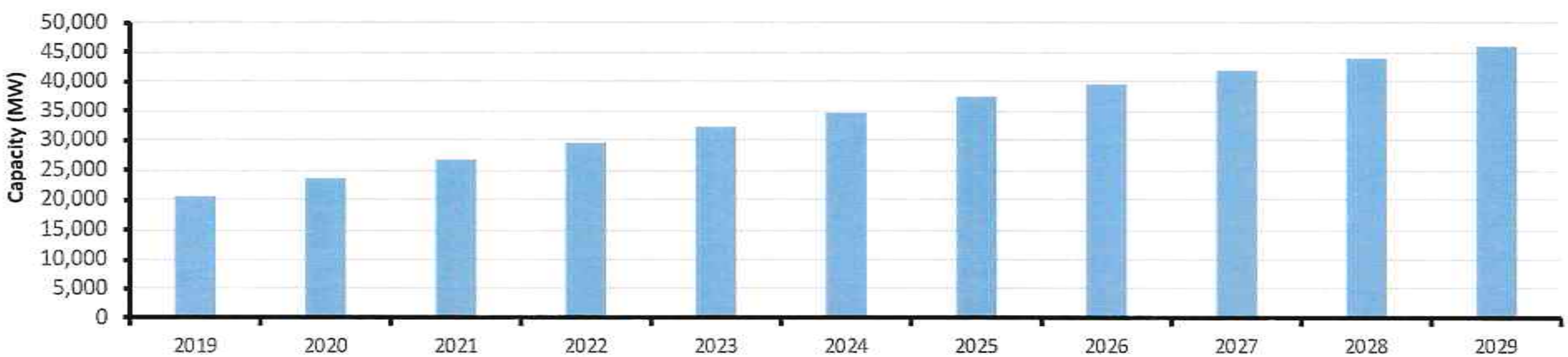


Figure 17: NERC-Wide Cumulative Distributed Solar PV Capacity—2019 through 2029

21 *NERC Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

Exhibit Bickett-4

Figure 18 shows the amount of DERs by assessment area by 2029. The amount of DERs being installed in WECC-CAMX is far beyond other assessment areas, totaling near 18,000 MW of solar DERs by 2029.

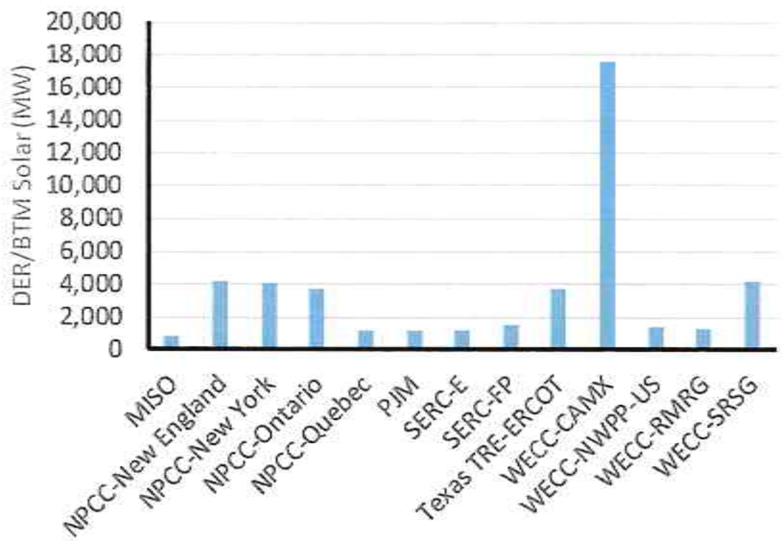


Figure 18: Solar DER by Assessment Area by 2029

Industry is already adapting by planning for the impacts of DERs. Some areas are already adapting in the following ways:

- **NPCC-New England:** To understand the possible impact of a large penetration of renewable and DERs in New England, the Region has conducted studies to simulate hypothetical resource scenarios for the years 2025 and 2030. These studies investigate the challenges of integrating renewable resources and transitioning New England to a hybrid system with decreasing amounts of traditional resources (e.g., coal, oil, and nuclear) and increasing amounts of renewable resources.
- **NPCC-New York:** Currently, DERs may participate in certain New York Independent System Operator (NYISO) energy, ancillary services, and capacity markets. In February 2017, the NYISO published a report providing a roadmap that the NYISO will use over the next three to five years as a framework to develop the market design elements, functional requirements, and tariff language necessary to implement the NYISO's vision to integrate DERs.
- **NPCC-Ontario:** The IESO is working, through the Grid-LDC Interoperability Standing Committee, to increase coordination between the grid operator and embedded resources directly or through integrated operations with local distribution companies with the aim to improve visibility of DERs and identify opportunities for a more coordinated operation of Ontario's electricity system.
- **Texas TRE-ERCOT:** ERCOT initiated several DER programs that have been approved by stakeholders, which were originally identified in the March 2017 ERCOT whitepaper[22] on DER reliability impacts. For example, all existing registered DERs (>1 MW that export to the ERCOT grid) are being mapped in the common information model (CIM) at their load point so that the DER locations will be visible to operators in the ERCOT control room and can be incorporated into the power flow, state estimator, and load forecast programs.
- **WECC:** The impacts of DERs on the individual LSEs are well understood and are in included in local assessments. For example, CAISO has approximately 11,800 MW of solar supply and must proportionally increase reserves to respond to a sudden increase in demand associated with cloud cover, rain, or inverter-related issues. Solar, rooftop or otherwise, is well dispersed throughout the state, which reduces the expectations of widespread generation disruptions due to localized weather conditions (overcast skies in Northern California with clear skies in Southern California).[23]

22 March 2017 ERCOT whitepaper on DER reliability impacts: http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf

23 In addition to local assessments, operating states are continuously monitored: http://www.caiso.com/TodaysOutlook/Pages/supply.aspx

Exhibit Bickett-4

Projection of Electric Storage Capacity

Energy storage has the potential to offer much needed capabilities to maintain grid reliability and stability. With the exception of pumped hydro storage facilities, only a limited number of large-scale energy storage demonstration projects have been built. With increasing requirements for system flexibility as variable generation levels increase and energy storage technology costs decrease, bulk system and distributed stationary energy storage applications may become more viable and prevalent. Storage may be used for load shifting and energy arbitrage—the ability to purchase low-cost, off-peak energy and re-sell the energy during high peak, high cost periods. Storage may also provide ancillary services such as regulation, load following, contingency reserves, and capacity. This is true for both bulk storage, which acts in many ways like a central power plant, and distributed storage technologies.

At the end of 2017, approximately 708 MW of utility-scale storage of differing types,[24] such as batteries, flywheels, and compressed air, was in operation. In California alone, legislation requires investor owned utilities to procure 1,325 MW of energy storage by 2020.[25] A total of 84 different projects across the United States are currently "planned," according to the U.S. Energy Information Administration. Based on the *2019 LTRA*, over 8 GW are currently planned (see Figure 19).

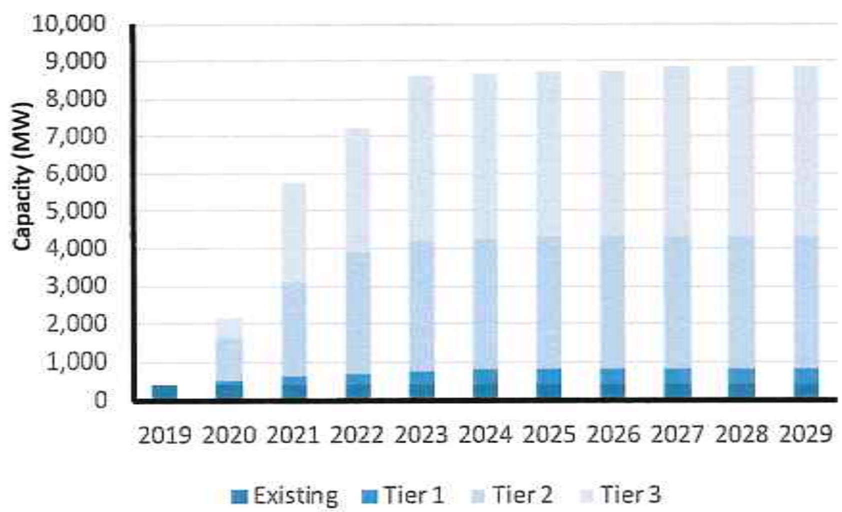


Figure 19: Total Existing and Planned Nameplate Energy Storage Capacity

24 This does not include pumped hydro storage.

25 https://www.eia.gov/analysis/studies/electricity/batterystorage/

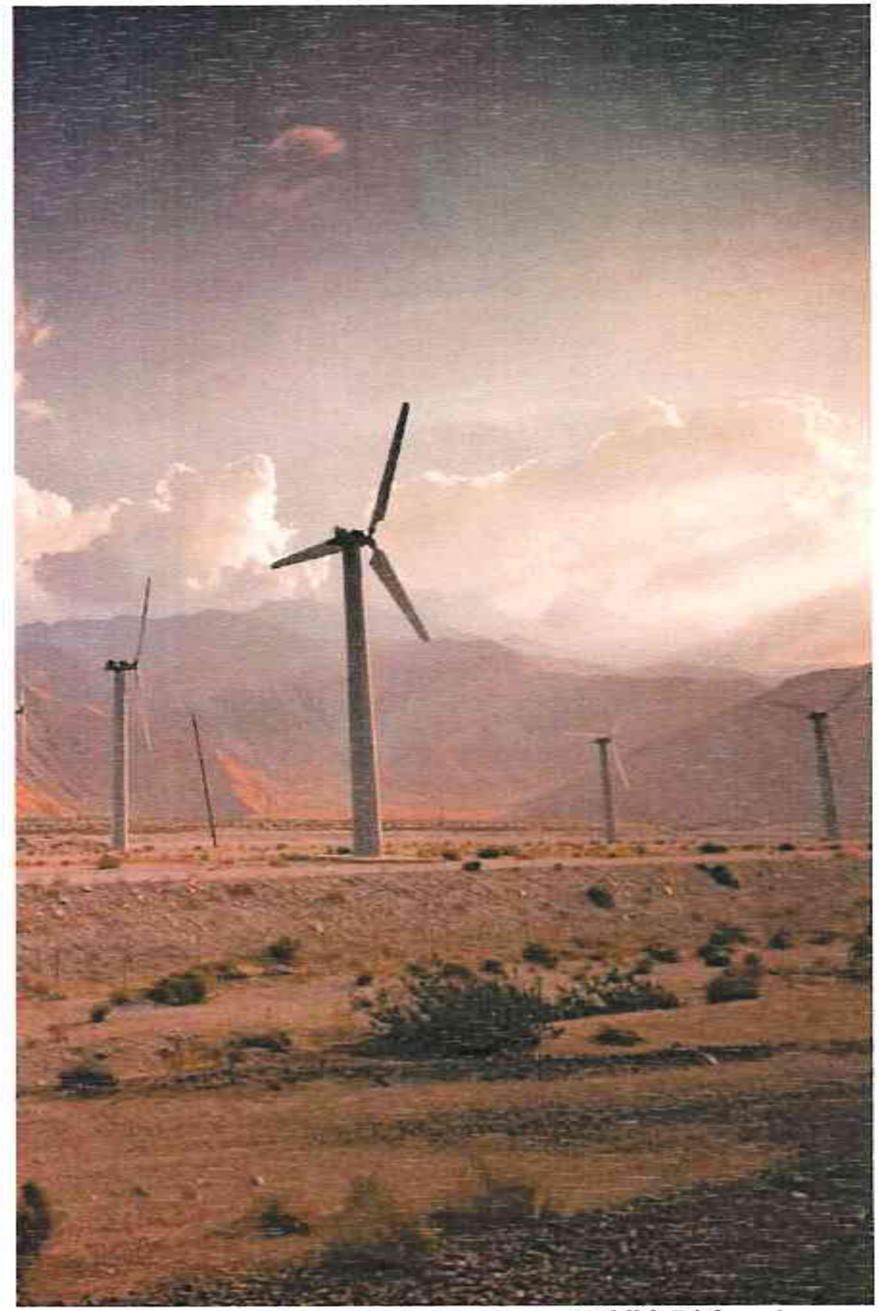


Exhibit Bickett-4

An illustrative example of the impacts of large amounts of solar on ramping can be found in Figure 20 that shows that as solar PV is added to a particular system, increased ramping capability is needed to support the increased ramping requirements. This is not a completely new concern for operators as some resources and imports have a long history of nondispatchability due to physical or contractual limitations. However, variable resources (particularly solar generation due to its daily production patterns) are the primary driver leading to increased ramping requirements. Other dispatchable resources are needed in reserve to offset the lack of electricity production when variable fuels (i.e., sun, wind) are not available.

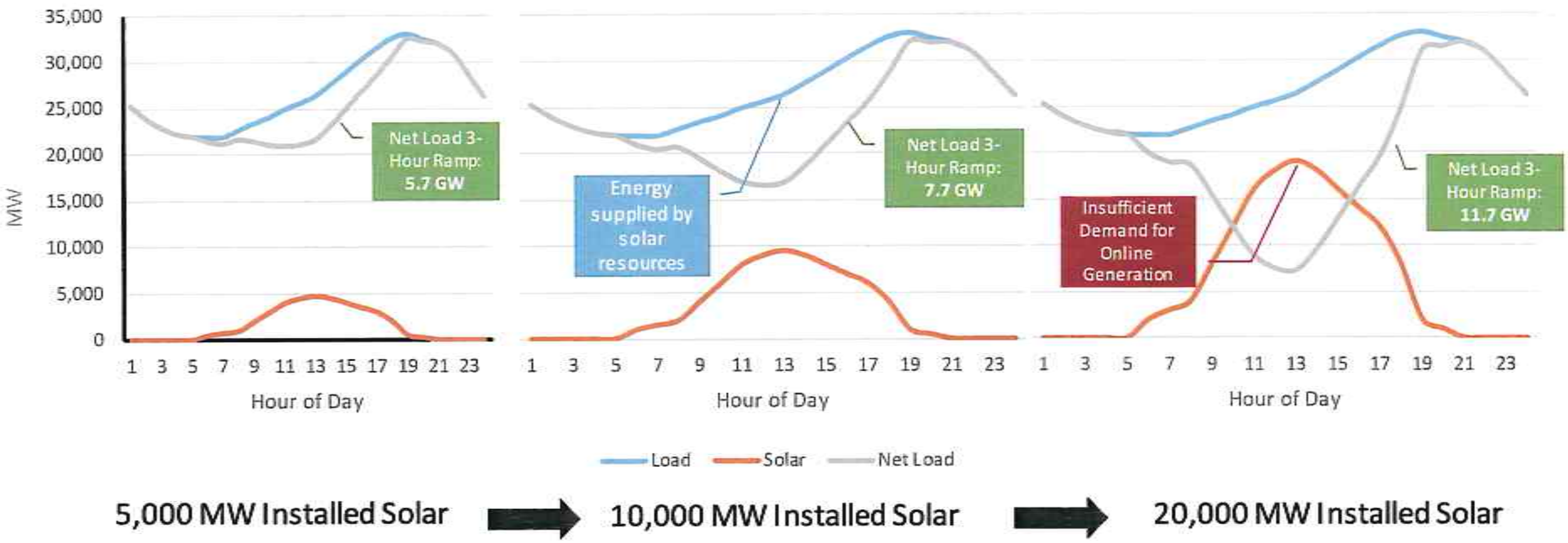


Figure 20: Example of Increasing Solar Resources Leading to Increased Ramping Requirements

Ramping

Ramping is a term used to describe the loading or unloading of generation resources in an effort to balance total generation and load during daily system operations. Changes in the amount of nondispatchable resources, system constraints, load behaviors, and the generation mix can impact the needed ramp capability and amount of flexible resources needed to keep the system balanced in real-time. For areas with an increasing penetration of nondispatchable resources, the consideration of system ramping capability is an important component of planning and operations. Therefore, a measure to track and project the maximum one-hour and three-hour ramps for each assessment area can help understand the significant need for flexible resources.

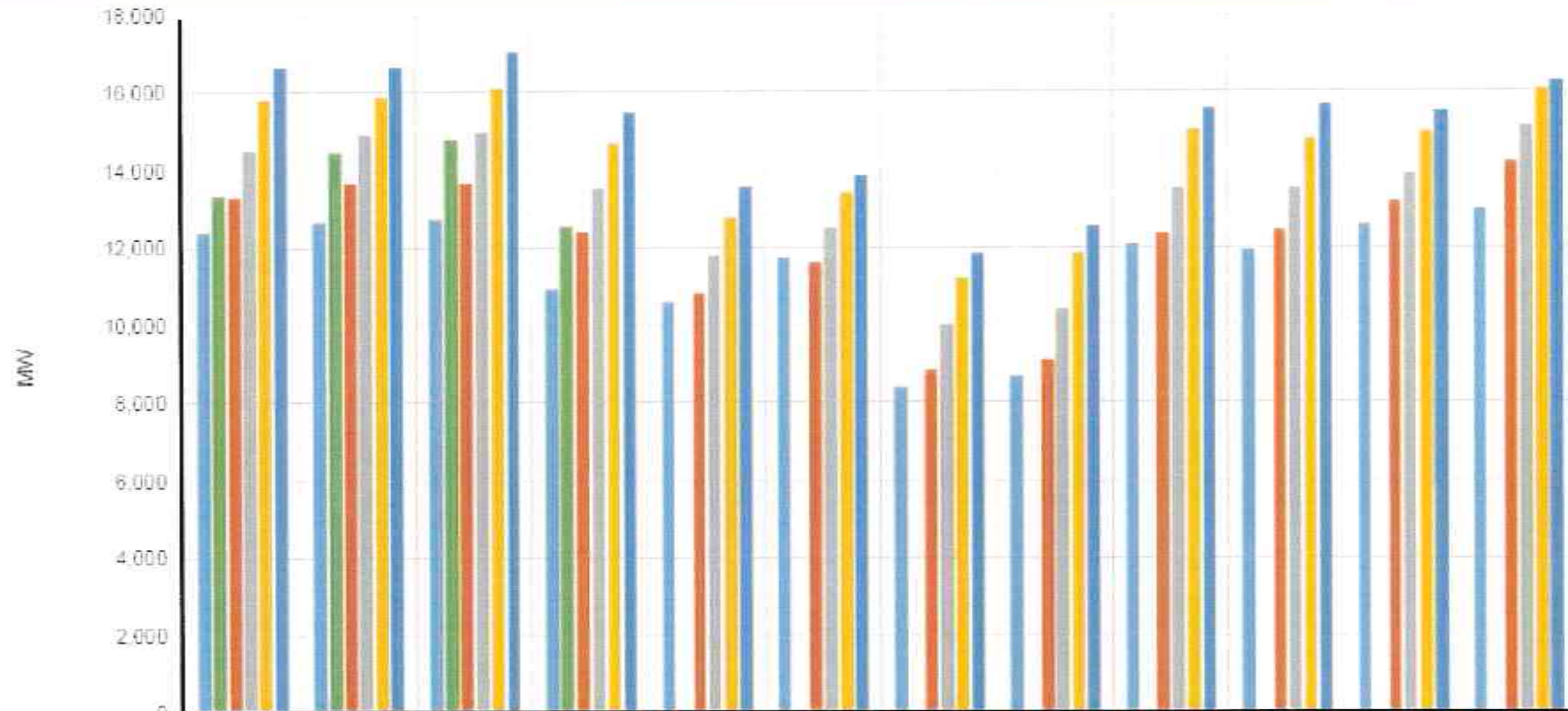
CAISO Photovoltaic Generation and Ramping

Predominant drivers for increasing ramps have been due to changes in California's load patterns, which can be attributed to an increased integration of solar PV DER generation across its footprint. For example, CAISO has approximately 11,800 MW of solar supply and must proportionally increase reserves to respond to a sudden increase in demand associated with cloud cover, rain, or inverter-related issues. Solar, rooftop or otherwise, is well dispersed throughout the state, which reduces the expectations of widespread generation disruptions due to localized weather conditions (overcast skies in Northern California with clear skies in Southern California).

With continued rapid growth of distributed solar, CAISO's three-hour net-load ramping needs have already exceeded 14 GW. Based on current projections, maximum three-hour upward net-load ramps are projected to exceed 17,000 MW in March by 2021, which is approximately 20% greater than the amount projected for 2018 (see Figure 21 on the next page). Upward ramping shortages are most prevalent in late afternoon when solar generation output decreases while system demand is still high. Without sufficient upward ramping capability within the balancing area to offset the loss of solar output during these times, neighboring balancing authorities would have to provide the necessary support to balance supply and demand.

Surpassing projections reinforces CAISO's near-term need for access to more flexible resources in their footprint:

- Currently, there are more than 13.3 GW of utility-scale and 8.2 GW of behind-the-meter (BTM) solar PV resources in WECC-CAMX's footprint, which has the most concentrated area of solar PV in North America.
- In March 2018, CAISO set a new ramping record with actual three hour upward net-load ramps reaching 14,777 MW. The maximum one hour net-load upward ramp was 7,545 MW. This record coincided with utility-scale solar PV, serving nearly 50% of the CAISO demand during the same time period.
- BTM solar PV has continued to grow in WECC-CAMX, and the projected BTM solar PV is expected to be 17.5 GW by 2029.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017 (Actual)	12,378	12,659	12,733	10,939	10,591	11,774	8,403	8,706	12,108	11,949	12,591	12,981
2018 (Actual)	13,326	14,440	14,777	12,553	0	0	0	0	0	0	0	0
2018_Forecast	13,310	13,668	13,669	12,380	10,832	11,618	8,836	9,093	12,355	12,437	13,184	14,197
2019_Forecast	14,506	14,889	14,971	13,509	11,808	12,524	9,967	10,393	13,511	13,510	13,898	15,129
2020_Forecast	15,784	15,877	16,110	14,664	12,762	13,404	11,187	11,823	15,024	14,791	14,993	16,057
2021_Forecast	16,674	16,677	17,048	15,450	13,546	13,864	11,817	12,536	15,575	15,679	15,507	16,296

Figure 21: Maximum Three-Hour Ramps in CAISO (Actual and Projected) through 2021

Emerging Reliability Considerations

Increasing amounts of DERs can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and essential reliability services. In certain areas, DERs are being connected on the distribution system at a rapid pace, sometimes with limited coordination between DER installation and BPS planning activities. With the rapid rate of DER installations on distribution systems, it will be necessary for the BPS planning functions to incorporate future DER projections in BPS models. These changes will affect not just the flow of power but also the behavior of the system during disturbances. As more DERs are added, system planners may needed to adapt their protection schemes to account for the changing system characteristics. There are at least two major events that have occurred on the European power system where the disconnection of DERs played a role in system collapse.[26] It is important to coordinate the planning, installation, and operation of DERs in relation to the BPS as transition to a new resource mix occurs. Specific emerging reliability considerations include the following:

- **Accommodating Large Amounts of DERs:** Today, the effect of aggregated DERs is not fully represented in BPS models and operating tools. This could result in unanticipated power flows and increased demand forecast errors. An unexpected loss of aggregated DERs could also cause frequency and voltage instability at sufficient DER penetrations. The system operator typically cannot observe or control DERs, so variable output from DERs can contribute to ramping and system balancing challenges. Overall, reliability risks concerning larger penetrations of DERs can be summarized by three major aspects:
    - Difficulty in obtaining and managing the amount of data concerning DERs, including their size, location, and operational characteristics
    - A current inability to observe and control most DERs in real time
    - A need to better understand the impacts on system operations of the increasing amounts of DERs, including ramping, reserve, frequency response, and regulation requirements
- **Accommodating Large Amounts of Bulk Electric Storage Systems (BESSs):** In addition to the potential safety issues of the devices themselves, BESSs introduce unique characteristics into the operation of the BPS. As BESSs do not convert fuel into electricity, it requires electricity for its charging that later is injected into the system. This appears as a demand on the rest of the system. In large penetrations, the energy for charging may not be available, and the state of charge for these resources may not be sufficient to perform when called upon. Coupled with the increasing penetrations of DERs and VERs, planning and operations need to enhance visibility and probabilistic forecasting and modelling.

Recommendations

The ERO and industry need to work together to ensure system studies incorporate DER impacts.

As the penetration of DERs continues to increase across the North American BPS, it is necessary to account for DERs in the planning, operation, and design of the BPS. System operators and planners should gather data as early as possible about the aggregate technical specifications of DERs connected to local distribution grids to ensure accurate and valid system planning device and simulation models, load forecasting, coordinated system protection, and real-time situation awareness. In areas with large or emerging DER penetrations, current operational models and system studies do not properly account for DERs. These models and studies will need to be improved to accurately represent the system's behavior.

The ERO should assess the implications of electricity storage on BPS planning and operations.

Electricity storage has the potential to offer much needed capabilities to the grid of the future. Based on data received in the resource information collected to support this assessment, there will be an increase of BPS-connected storage in the future; this may even be accelerated if the conditions are right. Before this storage is built and integrated into the BPS, the ERO should identify, assess, and report on the risks and potential mitigation approaches to accommodate large amounts of energy storage on BPS reliability.

26 See Italy Blackout 2003 and European Blackout 2006 **for more information.**

Exhibit Bickett-4

Key Finding 4: Transmission Planning and Infrastructure Ddevelopment Need to Keep Pace with an Increasing Amount of Utility Scale Wind and Solar Resources.

Key Points

- Under 15,000 circuit miles of new transmission is expected over the next 6 years, considerably less than the nearly 40,000 circuit miles earlier this decade.
- Many new VERs will be located in areas remote from demand centers and existing transmission infrastructure.

The existing electric transmission systems and planned additions over the next 10 years appear adequate to reliably meet customer electricity requirements. However, less and shorter lines are being constructed at a time when more and longer transmission is needed to accommodate large amounts of wind and solar resources. While a lack of future transmission projects does not currently pose a reliability concern, the importance of a secure transmission system is amplified when considering the significant addition of variable generation resources, continuing retirement of conventional and nuclear generation, and increased demand projections throughout North America in the assessment's 10-year horizon.

Transmission Projects

Figure 22 shows the historical 10-year transmission projections for the past 10 years, each year being a 10-year projection. Between the years 2010 and 2016 considerably more transmission was planned than more recent years. For example, in 2012, nearly 40,000 circuit miles of high voltage transmission was planned for the next 10 years. Current projections show less than 18,000 circuit miles of planned transmission for the next 10 years. Whether the planned transmission lines were actually constructed was not determined.

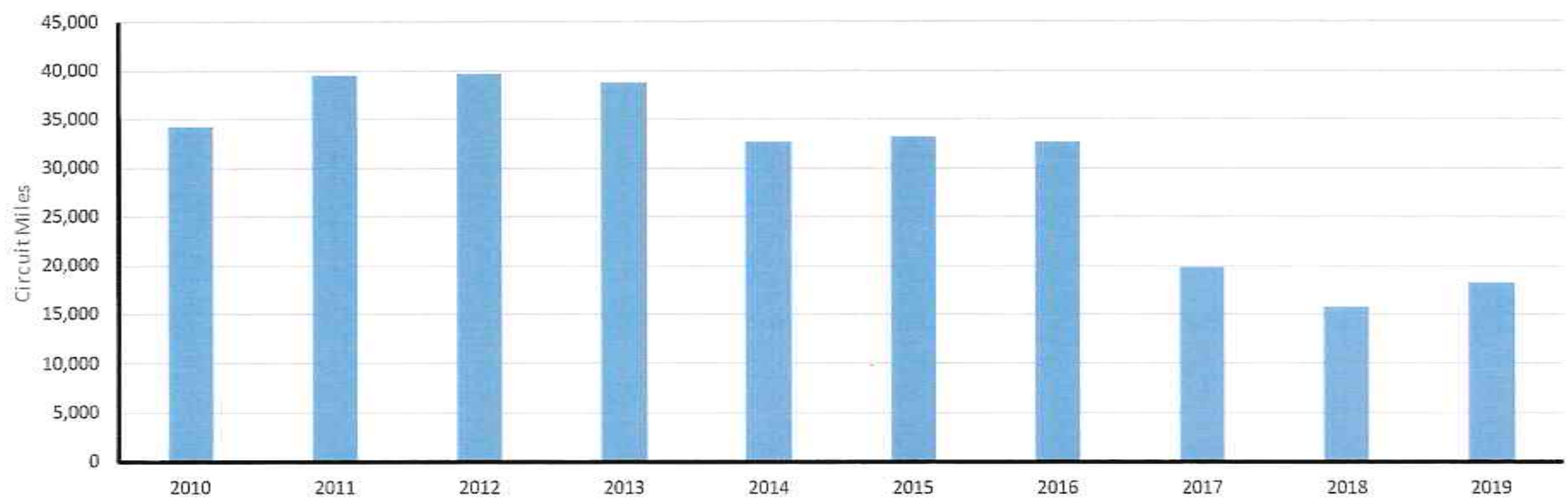


Figure 22: Historical 10-Year Transmission Projections

Exhibit Bickett-4

Future Transmission Project Categories

Under Construction: Construction of the line has begun.

Planned (any of the following):

- Permits have been approved to proceed
- Design is complete
- Needed in order to meet a regulatory requirement

Conceptual (any of the following):

- A line projected in the transmission plan
- A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as "Under Construction" or "Planned"
- Other projected lines that do not meet requirements of "Under Construction" or "Planned"

As part of the ERO assessment, information about future transmission projects is evaluated. Figure 23 highlights the transmission additions during the 10-year period include plans for over 18,000 circuit miles, including conceptual projects. This amount represents a considerable reduction in the amount of transmission miles planned in nearly a decade, compared with the 30,000+ miles planned each year during the period 2010–2016 (see Figure 22 on previous page).

Figure 24 shows that most planned transmission projects are shorter in line length, and fewer longer length projects are being planned. However, with the amount of solar and wind coming online in the next 10 years, area planning processes may identify needs for longer length transmission projects to capture and transmit renewable energy from areas distant from load centers.

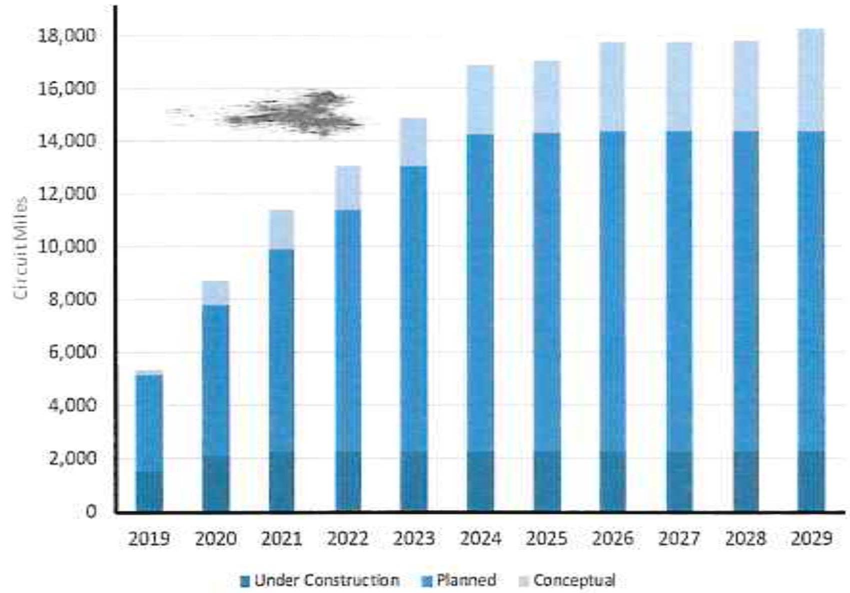


Figure 23: Cumulative 10-Year Projection of Planned Transmission

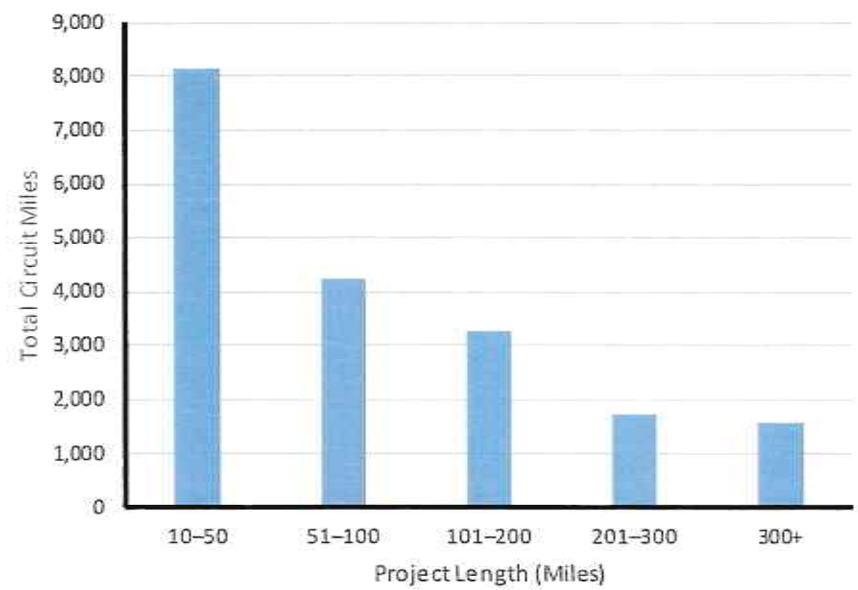


Figure 24: Line Miles Projected through 2029

Exhibit Bickett-4

Emerging Reliability Considerations
Additional transmission infrastructure is therefore vital to reliably accommodating large amounts of wind and solar resources, specifically in order to interconnect VERs planned in remote areas as well as to smooth the variable generation output across a broad geographical area and resource portfolio and deliver ramping capability and ancillary services from inside and outside a balancing area to equalize supply and demand.

Recommendation

In future assessments, the ERO should review challenges in transmission development and reliability risks due to the changing resource mix.
To accommodate large amounts of variable generation and to meet policy objectives associated with renewables in a reliable and economic manner, more transmission may be needed. For example, to meet the renewable energy requirements, transmission may be required to ensure that transfer of large amounts of energy can be supported when it becomes available. The ERO should assess and evaluate if the decreasing amount of transmission projects presents any future reliability risks or concerns.

Exhibit Bickett-4

Demand, Resources, Reserve Margins, and Transmission

Demand Projections

NERC-wide electricity peak demand and energy growth rates are up for the first in nearly 20 years, reaching its peak decline last year. The 2019 through 2029 aggregated projections of summer peak demand NERC-wide are slightly higher than last year's projection. A comparison of this year's 10-year forecasted growth to last year's 10-year forecasted growth indicates that peak demand is roughly flat for North America as a whole.

Figure 25 identifies the 10-year compound annual growth rate (CAGR) of peak demand that is increasing this year from the prior year—the lowest year on record. The projected 10-year energy growth rate is 0.60% per year compared to more than 1.48% just a decade earlier (Figure 26).

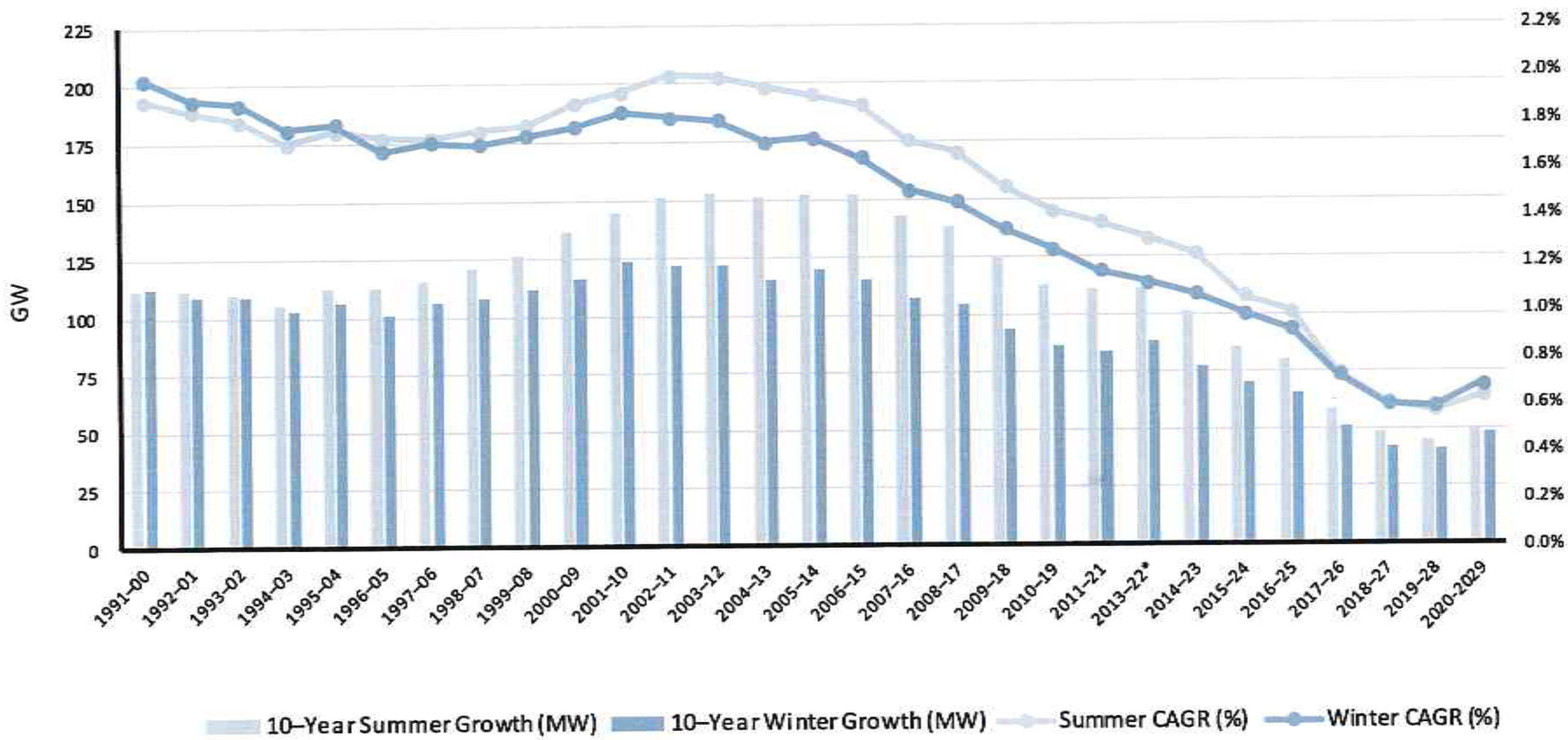


Figure 25: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

Exhibit Bickett-4

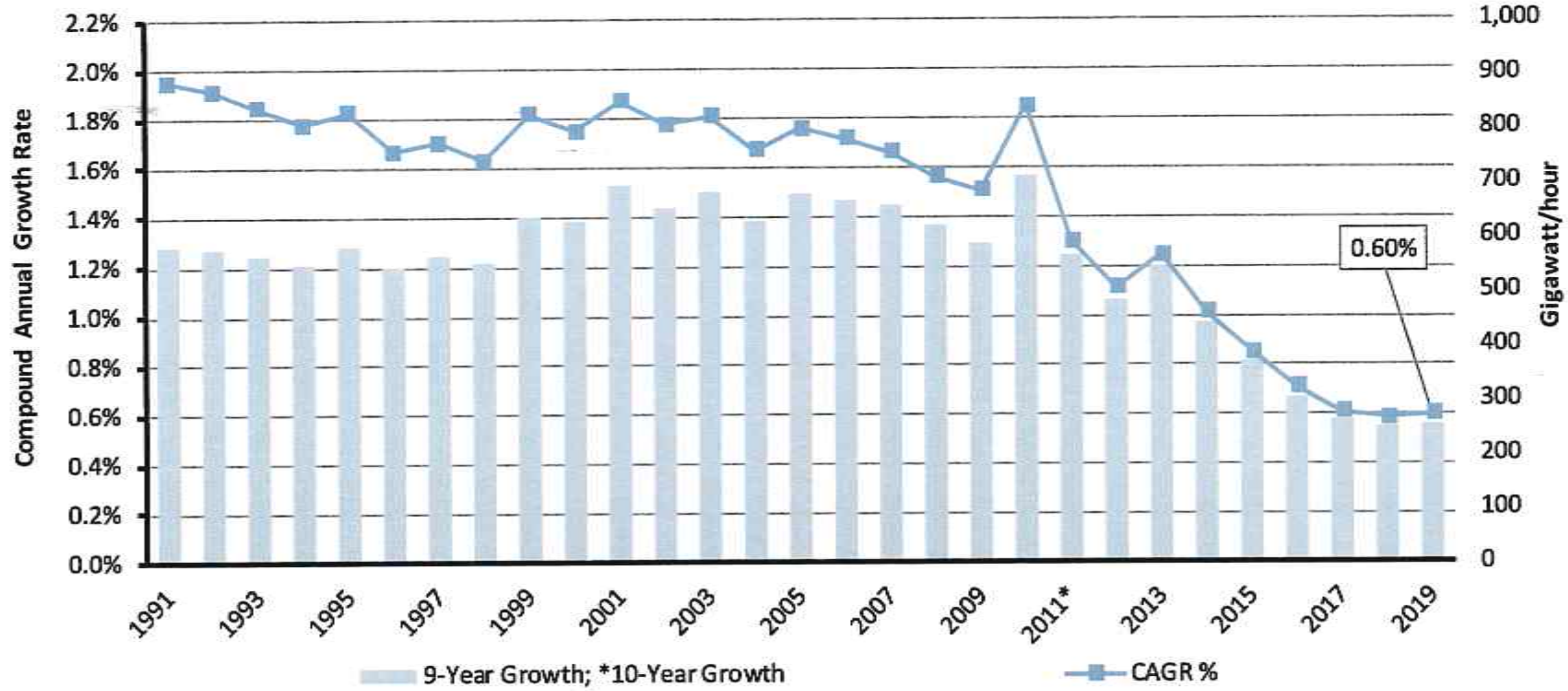


Figure 26: 10-Year Net Energy to Load Growth and Rate Trends

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise their forecasts on an annual basis or as their resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These forecasts are typically "equal probability" forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are internal electricity demands that have already been reduced to reflect the effects of demand-side management programs, such as conservation, EE, and time-of-use rates. It is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, dispatchable and controllable DRs are included in net internal demand.

Exhibit Bickett-4

The 10-year demand growth rate in all assessment areas is 2% or less per year with three assessment areas projecting reductions in peak demand (Figure 27).

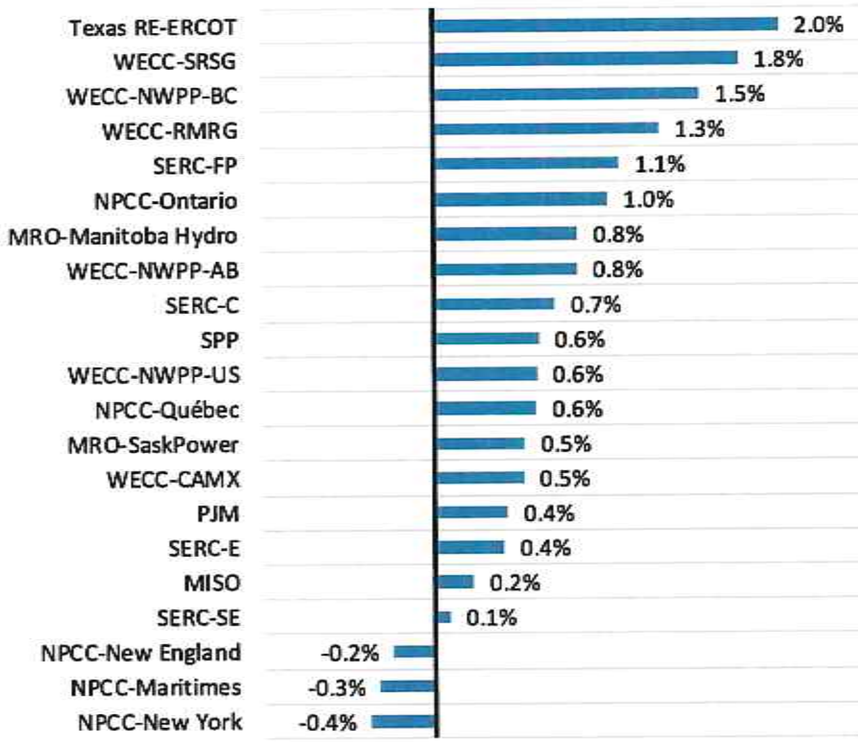


Figure 27: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area

Continued advancements of EE programs combined with a general shift in North America to less energy-intensive economic growth are contributing factors to slower electricity demand growth. Thirty states in the United States have adopted EE policies that are contributing to reduced peak demand and overall energy use.[27] Additionally, DERs and other behind-the meter resources continue to increase and reduce the net demand for the BPS even further.

The PRMs for the years 2020–2024 are shown in Table 3. Table 4 shows the Reference Margin Levels for each assessment area.

27 EIA - Today in Energy: Many states have adopted policies to encourage energy efficiency.

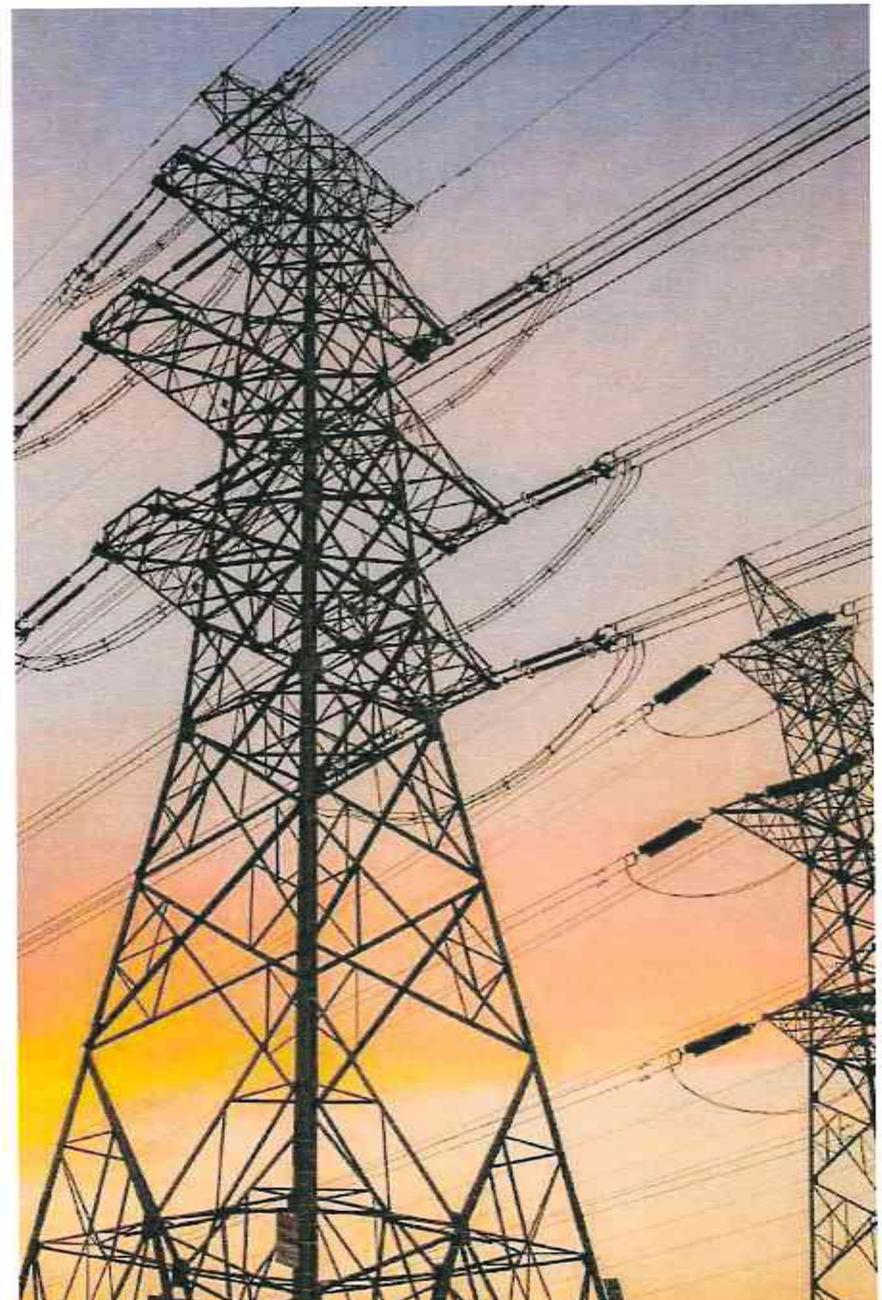


Exhibit Bickett-4

Reserve Margin Projections

Table 3: Planning Reserve Margin Years 2020–2024

Assessment Area	Reserve Margins (%)	2020	2021	2022	2023	2024
MISO	Anticipated Reserve Margin	22.5%	19.8%	18.7%	18.1%	17.5%
	Prospective Reserve Margin	20.8%	20.0%	26.3%	45.5%	53.5%
	Reference Margin Level	16.8%	16.8%	16.8%	16.8%	16.8%
MRO-Manitoba	Anticipated Reserve Margin	12.7%	15.8%	24.8%	22.6%	17.6%
	Prospective Reserve Margin	14.0%	17.1%	22.0%	19.8%	15.0%
	Reference Margin Level	12.0%	12.0%	12.0%	12.0%	12.0%
MRO-SaskPower	Anticipated Reserve Margin	23.3%	23.1%	19.8%	15.8%	16.6%
	Prospective Reserve Margin	23.3%	23.1%	21.1%	15.1%	16.0%
	Reference Margin Level	11.0%	11.0%	11.0%	11.0%	11.0%
NPCC-Maritimes	Anticipated Reserve Margin	22.4%	22.2%	21.3%	25.3%	26.0%
	Prospective Reserve Margin	25.3%	22.3%	21.4%	25.4%	24.3%
	Reference Margin Level	20.0%	20.0%	20.0%	20.0%	20.0%
NPCC-New England	Anticipated Reserve Margin	32.2%	31.7%	30.5%	26.7%	27.3%
	Prospective Reserve Margin	34.7%	35.6%	37.3%	36.7%	38.3%
	Reference Margin Level	18.5%	18.0%	17.8%	17.8%	17.8%
NPCC-New York	Anticipated Reserve Margin	25.3%	22.7%	23.0%	24.6%	25.3%
	Prospective Reserve Margin	26.2%	25.6%	26.0%	29.2%	30.0%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Ontario	Anticipated Reserve Margin	31.8%	30.1%	24.4%	15.3%	17.3%
	Prospective Reserve Margin	31.8%	30.1%	24.4%	15.3%	17.3%
	Reference Margin Level	26.4%	23.4%	23.3%	24.7%	20.1%
NPCC-Quebec	Anticipated Reserve Margin	13.1%	13.5%	13.3%	14.3%	13.7%
	Prospective Reserve Margin	16.0%	16.5%	16.3%	17.3%	16.7%
	Reference Margin Level	12.8%	12.8%	12.8%	12.8%	12.8%
PJM	Anticipated Reserve Margin	39.4%	39.3%	35.3%	34.8%	34.3%
	Prospective Reserve Margin	50.2%	55.9%	64.9%	68.1%	70.0%
	Reference Margin Level	15.9%	15.8%	15.7%	15.7%	15.7%
SERC-C	Anticipated Reserve Margin	39.8%	36.2%	35.1%	34.7%	32.0%
	Prospective Reserve Margin	46.3%	42.6%	41.5%	41.1%	38.4%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%

Assessment Area	Reserve Margins (%)	2020	2021	2022	2023	2024
SERC-E	Anticipated Reserve Margin	24.1%	24.6%	25.6%	24.9%	28.1%
	Prospective Reserve Margin	24.2%	24.7%	25.7%	25.0%	28.2%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-FP	Anticipated Reserve Margin	25.3%	24.3%	24.9%	26.2%	25.3%
	Prospective Reserve Margin	25.9%	24.9%	25.5%	26.7%	25.8%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-SE	Anticipated Reserve Margin	34.3%	33.9%	35.5%	37.3%	36.5%
	Prospective Reserve Margin	35.0%	35.9%	37.7%	39.4%	38.7%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SPP	Anticipated Reserve Margin	28.7%	26.5%	25.9%	24.5%	23.0%
	Prospective Reserve Margin	27.7%	25.4%	24.9%	23.5%	22.0%
	Reference Margin Level	12.0%	12.0%	12.0%	12.0%	12.0%
TRE-ERCOT	Anticipated Reserve Margin	10.2%	15.5%	13.0%	10.3%	7.8%
	Prospective Reserve Margin	18.7%	42.9%	47.2%	44.2%	41.0%
	Reference Margin Level	13.8%	13.8%	13.8%	13.8%	13.8%
WECC-AB	Anticipated Reserve Margin	23.9%	27.2%	22.7%	21.5%	20.9%
	Prospective Reserve Margin	26.6%	30.0%	25.3%	24.1%	23.5%
	Reference Margin Level	10.4%	10.4%	10.3%	10.2%	10.1%
WECC-BC	Anticipated Reserve Margin	16.2%	15.9%	14.7%	14.6%	14.8%
	Prospective Reserve Margin	16.2%	15.9%	14.7%	14.6%	14.8%
	Reference Margin Level	10.4%	10.4%	10.3%	10.2%	10.1%
WECC-CAMX	Anticipated Reserve Margin	17.2%	17.0%	15.6%	15.4%	15.7%
	Prospective Reserve Margin	21.0%	20.8%	19.4%	19.1%	19.4%
	Reference Margin Level	13.7%	13.9%	13.9%	13.8%	13.9%
WECC-NWPP-US	Anticipated Reserve Margin	23.2%	23.1%	22.1%	22.2%	22.1%
	Prospective Reserve Margin	23.4%	23.3%	22.3%	22.5%	22.4%
	Reference Margin Level	15.7%	15.7%	16.0%	15.9%	15.8%
WECC-RMRG	Anticipated Reserve Margin	25.8%	23.8%	22.4%	18.3%	16.7%
	Prospective Reserve Margin	25.8%	25.4%	23.9%	21.4%	19.8%
	Reference Margin Level	13.0%	12.0%	12.3%	12.5%	12.4%
WECC-SRSG	Anticipated Reserve Margin	20.5%	17.7%	17.1%	16.8%	14.5%
	Prospective Reserve Margin	21.3%	18.8%	18.2%	19.6%	17.2%
	Reference Margin Level	10.0%	11.0%	11.0%	11.0%	11.0%

Exhibit Bickett-4

Table 4: Reference Margin Levels for Each Assessment Area (2020–2024)

Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
MISO	17.1%	Planning Reserve Margin	Yes: Established Annually[28]	0.1/Year LOLE	MISO
MRO-Manitoba Hydro	12%	Reference Margin Level	No	0.1/Year LOLE/LOEE/ LOLH/EUE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	11%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
NPCC-Maritimes	20%[29]	Reference Margin Level	No	0.1/Year LOLE	Maritimes Subareas; NPCC
NPCC-New England	17.8–18.5%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1/Year LOLE	ISO-NE; NPCC Criteria
NPCC-New York	15%[30]	Installed Reserve Margin	Yes: one year requirement; established annually by NYSRC based on full installed capacity values of resources	0.1/Year LOLE	NYSRC; NPCC Criteria
NPCC-Ontario	18%–25%	Ontario Reserve Margin Requirement	Yes: established annually for all years	0.1/Year LOLE	IESO; NPCC Criteria
NPCC-Québec	12.9%	Reference Margin Level	No: established Annually	0.1/Year LOLE	Hydro Québec; NPCC Criteria
PJM	16.6%–16.7%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1/Year LOLE	PJM Board of Managers; Reliabili-ty*First* BAL-502-RFC-02 Standard
SERC-E	15%	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-FP	15%[31]	Reliability Criterion	No: Guideline	0.1/Year LOLP	Florida Public Service Commission
SERC-C	15%	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-SE	15%[32]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities

28 In MISO, the states can override the MISO Planning Reserve Margin.

29 The 20% Reference Margin Level is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

30 The NERC Reference Margin Level for NY is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an installed reserve margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. NYSRC approved the 2019–2020 IRM at 17.0%.

31 SERC-FP uses a 15% Reference Reserve Margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.

32 SERC does not provide Reference Margin Levels or resource requirements for its subregions. However, SERC members perform individual assessments to comply with any state requirements.

Exhibit Bickett-4

Table 4: Reference Margin Levels for Each Assessment Area (2020–2024)

Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
SPP	12%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1/Year LOLE	SPP RTO Staff and Stakeholders
TRE-ERCOT	13.75%	Target Reserve Margin	No	0.1/Year LOLE plus adjust-ment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	11.03%–11.22%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-BC	10.60%–12.10%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-CAMX[33]	14.76%–16.14%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-NWPP-US	16.38%–17.46%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-RMRG	11.65%–14.17%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-SRSG	12.02%–15.83%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC

33 California is the only state in the Western Interconnection that has a wide-area Planning Reserve Margin, currently 15%.

Transmission

Figure 28 highlights that ERO-wide transmission additions during the 10-year period include plans for over 18,000 circuit miles. NERC continues to monitor the progress of transmission projects across North America.

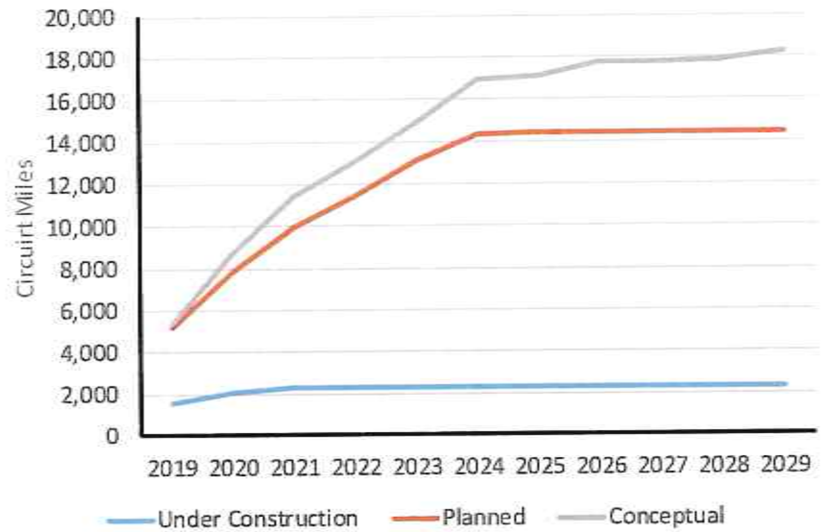


Figure 28: Future Transmission Circuit Miles >100 kV by Project Status

Figure 29 shows the future transmission circuit miles by voltage class.

Figure 30 shows the percentage of future transmission circuit miles by primary driver. According to industry, new transmission projects are being driven primarily to enhance reliability. Other reasons include congestion alleviation and integration of renewables. The breakdown of reasons for future transmission projects through 2029 are shown in Figure 30. As expected, most of the lines are coming in to address reliability, approximately 60%. Renewable integration will account for 1,400 miles of planned transmission.

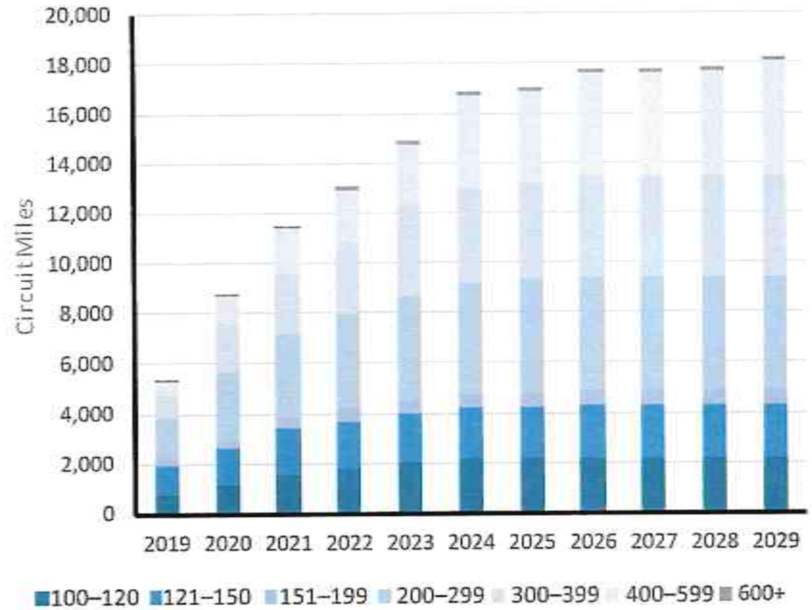


Figure 29: Future Transmission Circuit Miles >100 kV by Voltage Class

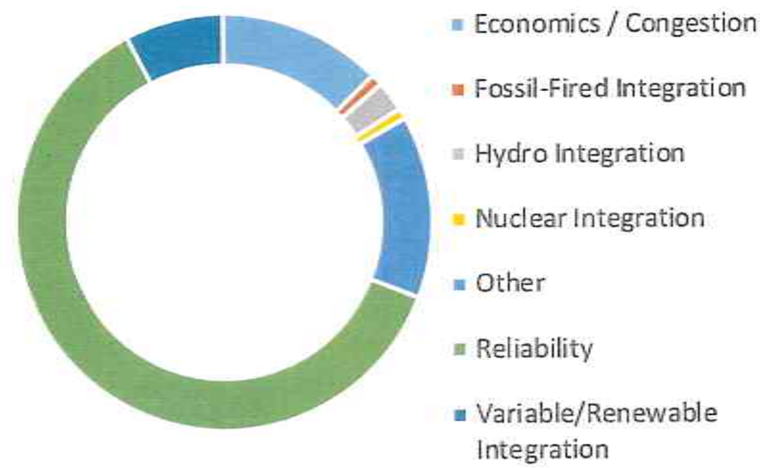


Figure 30: Future Transmission Circuit Miles by Primary Driver

Exhibit Bickett-4

Figure 31 shows the assessment areas as net importers or exporters for the year 2020 at the time of their seasonal peak. Net importers are shown in gold and net exporters are shown in blue. The grey assessment areas are below 100 MW of capacity imported or exported for 2020.

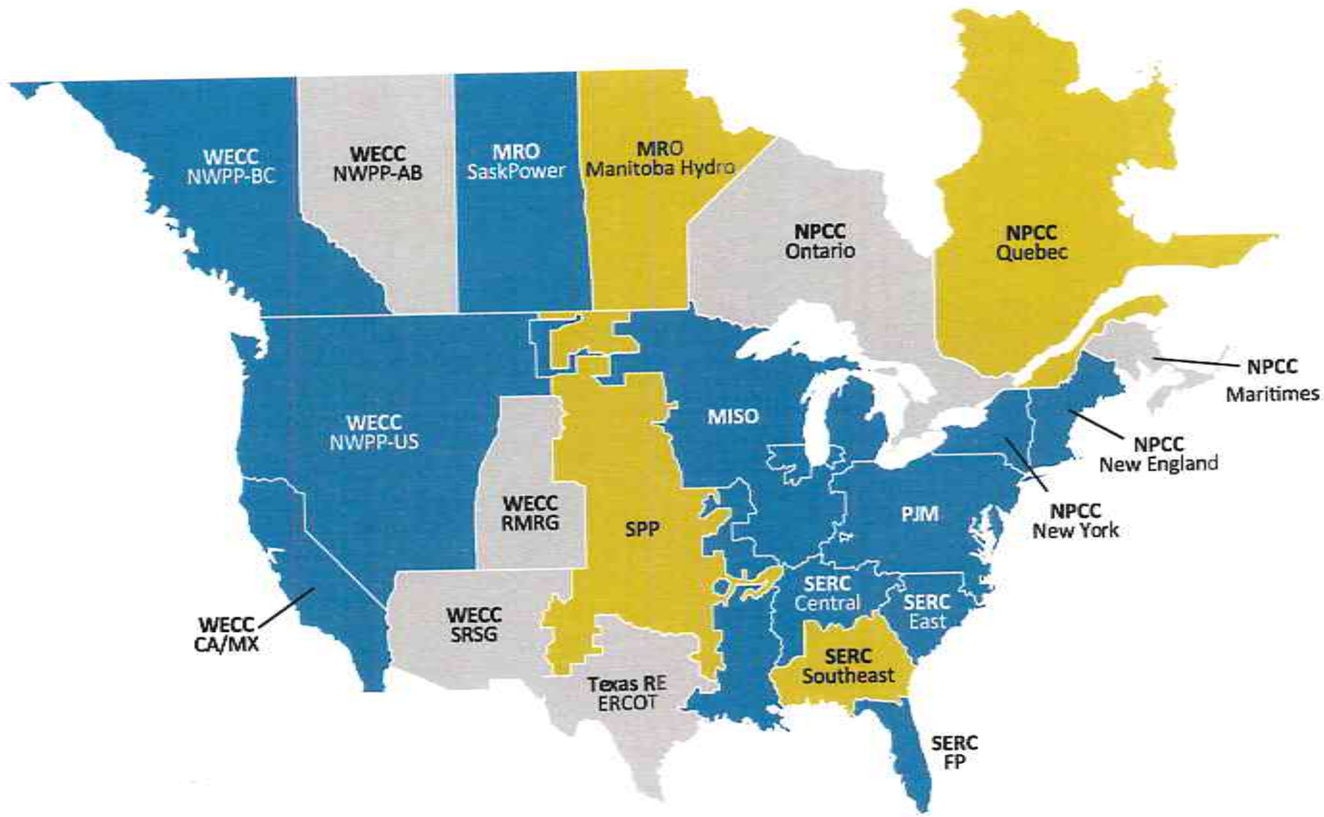


Figure 31: Net Transfers

Exhibit Bickett-4

Table 5 shows the percent of the reserve margin that is supported by net transfers. If an assessment area has a negative percentage, it is a net exporter. Conversely, if an assessment area has a positive percentage, it is a net importer.

Table 5: Net Transfers by Assessment Area

Assessment Area	Peak Demand (MW)	Firm Net Transfers (MW)	Reserve Margin (MW)	Percent of Reserve Margin	ACR
MISO	120,107	575	21,055	2.73%	141,162
MRO-Manitoba Hydro	4,757	(488)	839	-58.15%	5,597
MRO-SaskPower	3,883	100	646	15.48%	4,529
NPCC-Maritimes	5,300	-	1,380	0.00%	6,680
NPCC-New England	23,697	81	6,479	1.25%	30,176
NPCC-New York	30,618	1,939	7,745	25.04%	38,363
NPCC-Ontario	22,333	-	3,868	0.00%	26,202
NPCC-Quebec	37,081	(145)	5,082	-2.85%	42,163
PJM	144,192	-	49,417	0.00%	193,609
SERC-C	40,053	361	12,836	2.81%	52,889
SERC-E	45,083	530	12,681	4.18%	57,764
SERC-FP	47,015	1,132	20,555	5.51%	67,570
SERC-SE	45,909	(2,237)	16,762	-13.34%	62,671
SPP	54,011	(96)	12,448	-0.77%	66,458
TRE-ERCOT	81,891	50	6,401	0.78%	88,292
WECC-AB	12,321	-	2,575	0.00%	14,896
WECC-BC	12,430	410	1,837	22.32%	14,267
WECC-CAMX	54,835	2,020	8,586	23.53%	63,421
WECC-NWPP US	52,315	2,496	11,575	21.56%	63,890
WECC-RMRG	13,413	-	2,246	0.00%	15,659
WECC-SRSG	26,371	1,480	3,817	38.78%	30,187

Exhibit Bickett-4

Regional Assessments

The following regional assessments were developed based on data and narrative information collected by NERC from the REs on an assessment area basis. The RAS, at the direction of NERC's PC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information. A summary of the key data is provided in Table 6.

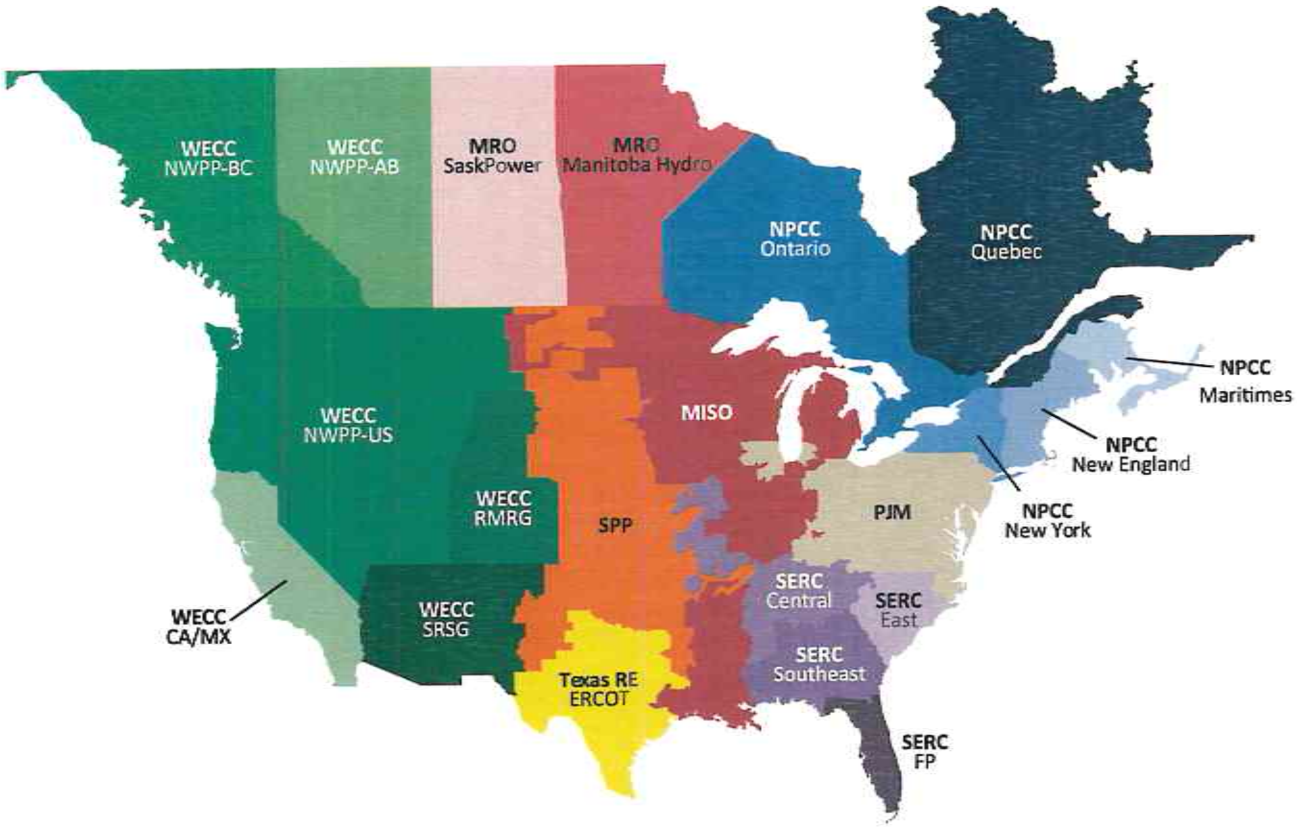
Table 6: Summary of 2024 Peak Projections by Assessment Area and Interconnection

	Net Internal Demand (MW)	Annual Net Energy for Load (GWh)	Net Transfers (MW)	Anticipated Capacity Resources	Anticipated Reserve Margin
MISO	120,107	647,218	575	141,162	17.5%
MRO-Manitoba	4,757	26,219	-488	5,597	17.6%
MRO-Sask	3,883	27,142	100	4,529	16.6%
NPCC-Maritimes	5,300	27,853	0	6,680	26.0%
NPCC-New England	23,697	120,544	81	30,176	27.3%
NPCC-New York	30,618	153,386	1,939	38,363	25.3%
NPCC-Ontario	22,333	139,912	0	26,202	17.3%
PJM	144,192	818,958	0	193,609	34.3%
SERC-C	40,053	219,670	361	52,889	32.0%
SERC-E	45,083	220,329	530	57,764	28.1%
SERC-FP	47,015	242,808	1,132	67,570	43.7%
SERC-SE	45,909	250,604	-2,237	62,671	36.5%
SPP	54,011	284,631	-96	66,458	23.0%
WECC-AB	12,321	89,223	0	14,896	20.9%
WECC-BC	12,430	68,275	410	14,267	14.8%
WECC-CAMX	54,835	273,162	2,020	63,421	15.7%
WECC-NWPP US	52,315	311,394	2,496	63,890	22.1%
WECC-RMRG	13,413	76,710	0	15,659	16.7%
WECC-SRSG	26,371	123,140	1,480	30,187	14.5%
EASTERN INTERCONNECTION	586,960	3,179,273	1,897	753,671	N/A
QUEBEC INTERCONNECTION	37,081	200,604	-145	42,163	13.7%
TEXAS INTERCONNECTION	81,891	450,426	50	88,292	7.8%
WESTERN INTERCONNECTION	171,685	941,904	6,406	202,320	N/A

Exhibit Bickett 4

NERC Assessment Areas

In order to conduct NERC reliability assessments, NERC further divides the Regional Entities into 21 assessment areas, shown below. This level of granularity allows NERC to better evaluate resource adequacy and ensure deliverability constraints between and among assessment areas are accounted for.



MRO—Midwest Reliability Organization
- MRO-SaskPower
- MRO-Manitoba Hydro
- MISO

SPP—Southwest Power Pool
- SPP

Texas RE—Texas Reliability Entity
- ERCOT

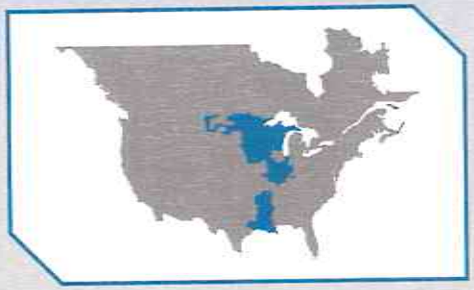
NPCC—Northeast Power Coordinating Council
- NPCC-New England
- NPCC-Maritimes
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

RF—ReliabilityFirst
- PJM

WECC—Western Electricity Coordinating Council
- WECC-BC
- WECC-AB
- WECC-RMRG
- WECC-CA/MX
- WECC-SRSG
- WECC-NWPP-US

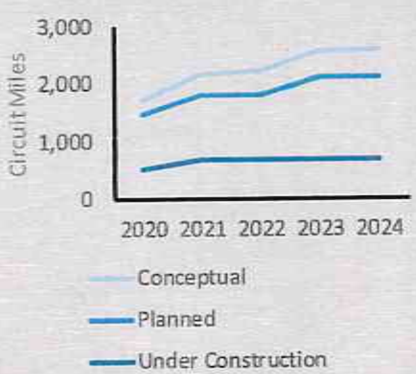
SERC—SERC Reliability Corporation
- SERC-East
- SERC-Central
- SERC-Southeast
- SERC-FP

Exhibit Bickett-4



MISO

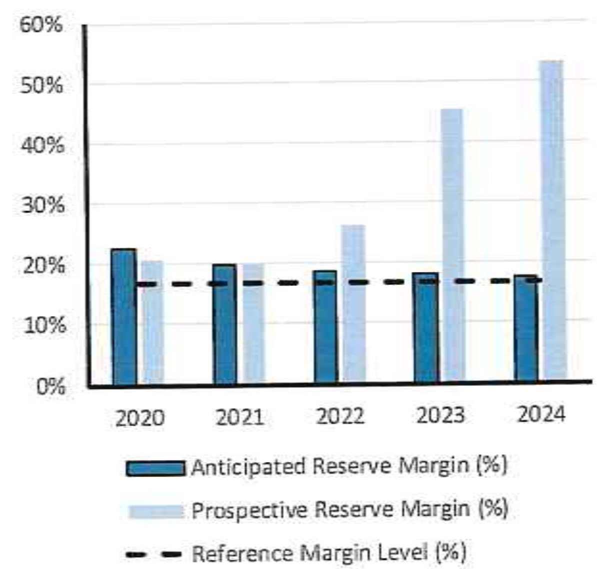
MISO is a not-for-profit, member-based organization that administers the wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities (BAs) and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.



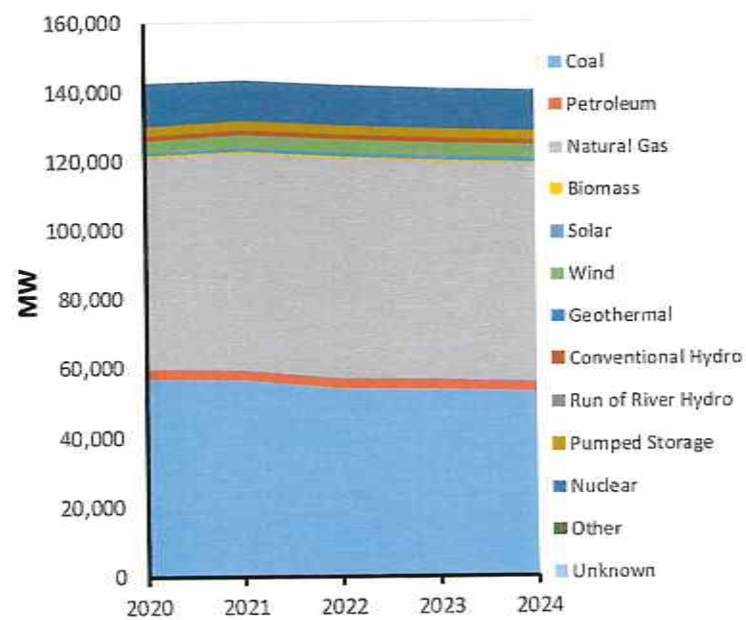
Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)

Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	124,809	125,664	125,818	125,984	126,122	126,307	126,322	126,658	127,013	127,316
Demand Response	5,959	5,986	5,985	5,989	6,014	6,017	6,019	6,023	5,992	5,992
Net Internal Demand	118,849	119,678	119,833	119,995	120,107	120,290	120,304	120,635	121,020	121,323
Additions: Tier 1	2,343	5,370	6,659	6,759	6,879	6,879	6,879	6,879	6,879	6,879
Additions: Tier 2	600	2,811	10,097	36,283	47,275	47,800	47,800	47,800	47,800	47,800
Additions: Tier 3	1,456	3,524	5,117	6,332	8,429	8,504	9,784	10,256	11,028	11,028
Net Firm Capacity Transfers	1,426	579	578	577	575	-287	-278	-279	-281	-283
Existing-Certain and Net Firm Transfers	143,235	137,949	135,637	134,965	134,283	132,973	132,863	132,005	131,670	131,753
Anticipated Reserve Margin (%)	22.49%	19.75%	18.74%	18.11%	17.53%	16.26%	16.16%	15.13%	14.48%	14.27%
Prospective Reserve Margin (%)	20.84%	20.02%	26.30%	45.46%	53.46%	52.00%	51.60%	50.03%	48.36%	48.06%
Reference Margin Level (%)	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Bickett-4

Highlights

- The MISO area is projected to have resources in excess of the regional requirement. Through 2022, regional surpluses and potential resources are sufficient for all zones to serve their deficits although there are two resource zones that are operating near local resource adequacy requirements. Affected MISO members and regulatory bodies are working to address in their respective resource plans.
- Continued focus on load growth variations and resource mix changes will allow for transparency around future resource adequacy risk.
- As MISO continues to operate near the PRM, it is important to ensure efficient conversion of committed capacity to energy that is able to serve near term load and not just on-peak but for all hours of the year. MISO has embarked on an initiative called resource availability and need (RAN) to review gaps in this conversion. Highlights of this initiative are as follows:
    - The RAN effort aims to address resources availability, visibility, and flexibility in several stages over the coming year.
    - The near-term focus has been improved outage scheduling and load modifying resource requirements.
    - The longer-term focus is capacity accreditation, seasonal resource adequacy, improved visibility, and market incentives in the operating horizon.
- To ensure visibility into fuel assurance to support system reliability, MISO utilizes data from the annual winter generator fuel survey for all natural gas generators to create fuel assurance ratings for generators based on transportation type, number of natural gas system connections, back-up fuel capability, and access to flexible services. In addition, MISO continues to make steady progress on incorporating major natural gas pipeline disruptions in planning studies to assess potential reliability risks.
- MISO is working with its members and regulators through the Organization of MISO States (OMS) and their DER survey to determine the current state of DERs at MISO and to strategize how to plan for increasing DERs into the future.
- MISO continues to work with policymakers and stakeholders to understand overall system needs and explore long range planning efforts that provide insights to inform decisions. MISO has begun a series of planning futures workshops to develop a broad set of future scenarios, providing long-term views of future resource portfolios.

MISO Fuel Composition										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	56,795	56,406	53,932	53,560	52,770	52,710	52,513	51,839	51,839	51,839
Petroleum	2,982	2,900	2,880	2,832	2,832	2,668	2,668	2,668	2,668	2,668
Natural Gas	61,526	63,241	64,077	63,364	63,362	63,018	62,096	61,851	61,564	61,564
Biomass	403	389	389	366	341	336	336	263	263	263
Solar	714	1,002	1,127	1,227	1,227	1,227	1,227	1,227	1,227	1,227
Wind	3,418	3,565	3,624	3,607	3,724	3,718	3,688	3,684	3,665	3,665
Conventional Hydro	1,531	1,560	1,560	1,486	1,486	1,358	1,358	1,358	1,352	1,352
Pumped Storage	2,761	2,762	2,762	2,762	2,762	2,733	2,733	2,733	2,733	2,733
Nuclear	12,433	11,620	11,620	11,620	11,620	11,620	11,620	11,620	11,620	11,620
Other	20	20	20	20	20	20	20	20	20	20
Total MW	142,583	143,464	141,990	140,844	140,144	139,407	138,257	137,263	136,951	136,951

Exhibit Bickett-4

MISO Assessment

Planning Reserve Margins: As directed under Module E-1 of the MISO Tariff, MISO coordinates with stakeholders to determine the appropriate PRM for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO coincident peak demand for that planning year. The probabilistic analysis uses a loss of load expectation (LOLE) study that assumes no internal transmission limitations within the MISO Region. MISO calculates the PRM such that the LOLE for the next planning year is 1 day in 10 years, or 0.1 days per year. The minimum amount of capacity above coincident peak demand in the MISO area required to meet the reliability criteria is used to establish the PRM. The PRM is established as an unforced capacity (PRM UCAP) requirement based upon the weighted average forced outage rate of all planning resources in the MISO Region. The PRM decreased from the *2018 LTRA* of 17.1%–16.8% on an installed capacity basis in this *2019 LTRA*. Changes from 2018–2019 planning year values are due to changes in load profiles and changes in the resource mix—retirements, additions, and suspensions.

Demand: MISO does not forecast load for the seasonal resource assessments. Instead, LSEs report load projections under the Resource Adequacy Requirements section (Module E-1) of the *MISO Tariff*. LSEs report their annual load projections on a MISO coincident basis as well as their non-coincident load projections for the next 10 years, monthly for the first 2 years and seasonally for the remaining 8 years. MISO projects the summer coincident peak demand is expected to grow at an average annual rate of 0.2% for the 10-year period. This is down a tenth of a percentage point from the 2018 assessment.

Demand-Side Management: MISO currently separates demand response resources into two categories: direct control load management and interruptible load.[34] Direct control load management is the magnitude of customer service (usually residential). During times of peak conditions, or when MISO otherwise forecasts the potential for maximum generation conditions, MISO surveys local BAs to obtain the amount of their demand. For this assessment, MISO uses the registered amount of demand-side management that is procured and cleared through the annual planning resource auction. MISO forecasts 5,959–5,992 MW of direct control load management and interruptible load to be available for the assessment period. MISO also forecasts at least 4,582 MW of BTM generation to be available for assessment period. EE is not explicitly forecasted at MISO; the majority of EE programs are reflected within the demand and energy forecasts; however, 312 MW were offered in the 2019–2020 planning resource auction.

34 See BPM 011 section 4.3 of the MISO Resource Adequacy Business Practice Manual: https://www.misoenergy.org/legal/business-practice-manuals/

Distributed Energy Resources: As part of the MISO Transmission Expansion Plan (MTEP) study, there was an attempt to collect information on DERs. The forecast provides an estimate of DER programs and their impact on peak demand and annual energy savings. This forecast positions MISO to understand emerging technologies and the role they play in transmission planning as there is a specific case on DERs both at a base case level and an increased penetration level. MISO has not experienced any operational challenges as of yet but expects to as programs grow in the future. Soliciting current DER levels and methods of forecasting at MISO are an ongoing effort. To-date, the best source of existing DERs is a survey conducted annually by the Organization of MISO States, or Outage Management System (OMS). The 2019 OMS DER survey showed about 4.5 GW of DERs in the MISO footprint, 850 MW of which is BTM solar PV.

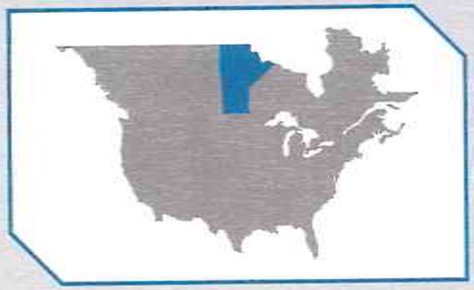
Generation: MISO projects approximately 3.1 GW of generation capacity to retire in 2019. Through the generator interconnection queue (GIQ) and the OMS MISO survey process, MISO anticipates 11.7 GW of future potential capacity additions to be in-service and expected on-peak during the assessment period. This is based on a snapshot of the GIQ and the *2019 OMS–MISO Survey* as of June 2019, including the aggregation of active projects.

Capacity Transfers: Interregional planning is critical to maximize the overall value of the transmission system and deliver savings for customers. Interregional studies conducted jointly with MISO's neighboring planning authorities are based on an annual review of transmission issues at the seams. Depending on the outcome of those reviews, studies are scoped out and performed. In the *MTEP 2018*,[35] two interregional projects with PJM were recommended for approval.

Transmission: The annual MTEP establishes the recommended regional plan that integrates expansion based on reliability, transmission access, market efficiency, and public policy needs across all planning horizons with the goal of maintaining a reliable electric grid and delivering the lowest-cost energy to customers in MISO. Major categories of planned transmission in *MTEP 2018* include the following: a total of 81 baseline reliability projects required to meet NERC Reliability Standards; 16 generator interconnection projects required to reliably connect new generation to the transmission grid, 2 interregional targeted market efficiency projects with PJM; and 346 other projects primarily driven by local reliability, load interconnection, age condition, and other local needs.

35 The full 2018 report is available at the following link: https://cdn.misoenergy.org/MTEP18%20Full%20Report264900.pdf

Exhibit Bickett-4

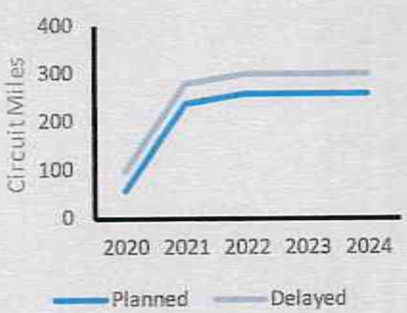


MRO-Manitoba Hydro

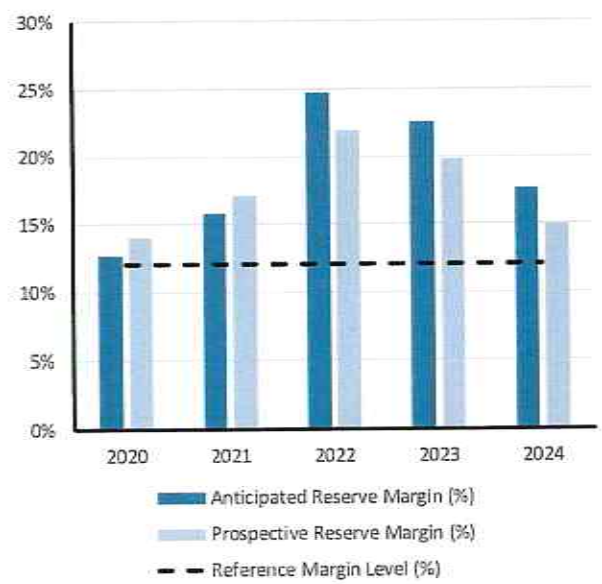
Manitoba Hydro is a provincial crown corporation providing electricity to about 580,000 electric customers in Manitoba and about 282,000 natural gas customers in Southern Manitoba. The service area is the province of Manitoba that is 250,946 square miles. Manitoba Hydro is winter-peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and BA. Manitoba Hydro is a coordinating member of the MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins (MW)

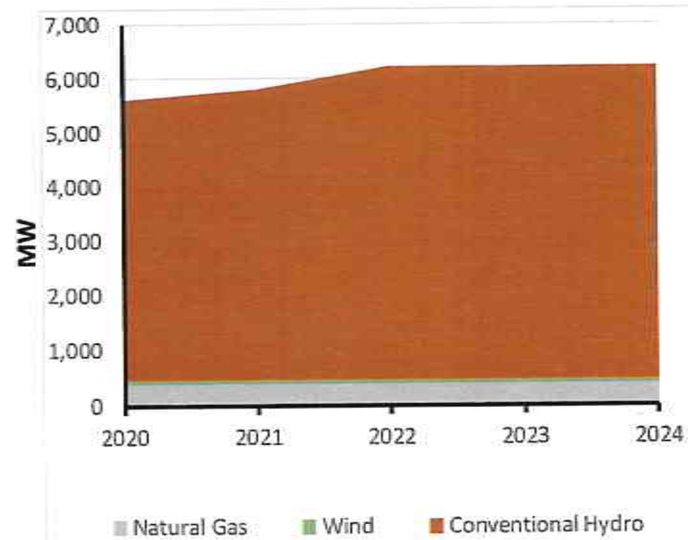
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	4,518	4,503	4,535	4,569	4,757	4,776	4,804	4,817	4,838	4,868
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,518	4,503	4,535	4,569	4,757	4,776	4,804	4,817	4,838	4,868
Additions: Tier 1	0	193	645	645	645	645	645	645	645	645
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-376	-447	-427	-483	-488	-424	-424	-329	-252	-257
Existing-Certain and Net Firm Transfers	5,093	5,022	5,013	4,957	4,952	5,016	4,995	5,090	5,167	5,151
Anticipated Reserve Margin (%)	12.74%	15.82%	24.78%	22.61%	17.64%	18.53%	17.41%	19.07%	20.14%	19.05%
Prospective Reserve Margin (%)	14.03%	17.11%	21.96%	19.81%	14.96%	15.85%	14.75%	16.41%	17.50%	16.30%
Reference Margin Level (%)	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Bickett-4

Highlights

- The ARM does not fall below the Reference Margin Level of 12% in any year during the assessment period. The 630 MW (net summer addition) Keeyask Hydro Station is expected to come into service beginning in the winter of 2021–2022, helping to ensure resource adequacy in the latter half and after the end of the current assessment period. No resource adequacy issues are expected.
- Demand is flattening over the LTRA horizon as a result of reduced load growth and EE/conservation efforts.
- Since the *2018 LTRA*, Manitoba Hydro experienced 115 MW (nameplate) of confirmed retirements, consisting of 100 MW of coal generation and 15 MW of hydro generation.

Manitoba Hydro Fuel Composition

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Natural Gas	404	404	404	404	404	404	404	404	404	404
Wind	52	52	52	52	52	52	31	31	31	31
Conventional Hydro	5,148	5,341	5,764	5,764	5,764	5,764	5,764	5,764	5,764	5,753
Total MW	5,604	5,797	6,220	6,220	6,220	6,220	6,199	6,199	6,199	6,188

Exhibit Bickett-4

MRO-Manitoba Hydro Assessment

Planning Reserve Margins: The ARM does not fall below the Reference Margin Level of 12% in any year during the assessment period. The Reference Margin Level is based on both system historical adequacy performance analysis and reference to probabilistic resource adequacy studies using the index of loss of load expectation LOLE and loss of energy expectation (LOEE).

Demand: Manitoba Hydro's load peaks in the winter, typically in the months of January, February, or December. The primary driver of energy load growth in Manitoba is population with the secondary driver being the economy. Manitoba Hydro's system energy/energy forecasting methodology is primarily based on three market segments: residential, general service mass market, and top consumers (Manitoba Hydro's largest industrial customers) with a small amount remaining for miscellaneous groups composing of street lighting and seasonal customers. Manitoba Hydro uses econometric regression modeling by sector to determine projected energy usage. There have been no footprint changes and no significant changes to the forecast methodology since the *2018 LTRA*.

Demand-Side Management: Manitoba Hydro does not have any demand-side management resources that are considered controllable and dispatchable demand response. Manitoba Hydro does have EE and conservation initiatives used to reduce overall demand in the assessment area, and the impact of the reductions are included in the load forecast.

Distributed Energy Resources: There are approximately 19 MW dc of solar DERs in Manitoba as of the end of March 2019. Most of the solar distributed resources were installed in the last two years under an incentive program that has ended. Even with high growth rates, Manitoba Hydro is not anticipating that the quantity of solar DERs in Manitoba would increase to a level that would cause potential operation impacts in the next five years.

Generation: The 630 MW (net summer addition) Keeyask Hydro Generating Station is scheduled to come into service beginning in the winter of 2021–2022. The Keeyask hydro station has been under construction for several years and the major concrete work is now almost 90% complete. The completion of the Keeyask hydro station will help ensure resource adequacy in the latter half and after the end of the current assessment period. The additional hydro generation will support a related 250 MW capacity transfer into the MISO Region and an expected capacity transfer of 190 MW to SaskPower.

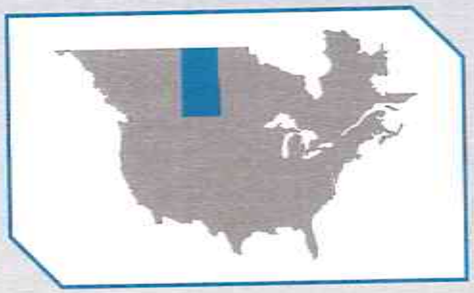
Brandon Unit 5 (100 MW nameplate), a coal-fired generator, was a confirmed retirement effective August 2018. The driver of the retirement of Brandon Unit 5 was both environmental and end of lifespan. Pointe du Bois Units 3, 5, 7, and 11 (total of 15 MW nameplate) were confirmed retirements effective August 2018 due to age and economic reasons. The retirement of these units did not result in adverse reliability impacts as the Reference Margin Level was maintained.

Capacity Transfers: The Manitoba Hydro system is winter peaking and is interconnected to the MISO Zone 1 local resource zone, which includes Minnesota and North Dakota and is summer-peaking as a whole. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only if the following conditions simultaneously occur: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint.

The additional hydro generation from Keeyask and the related 250 MW capacity transfer into the MISO area will tend to increase north to south flows on the Manitoba-MISO interface. A 100 MW capacity transfer from Manitoba to Saskatchewan will tend to increase east to west flow on the Manitoba–Saskatchewan interface once the 230 kV Birtle to Tantallon line is in-service in 2021. An expected capacity transfer of 190 MW from Manitoba to Saskatchewan that begins in 2022 will also tend to increase east to west flow on the Manitoba–Saskatchewan interface.

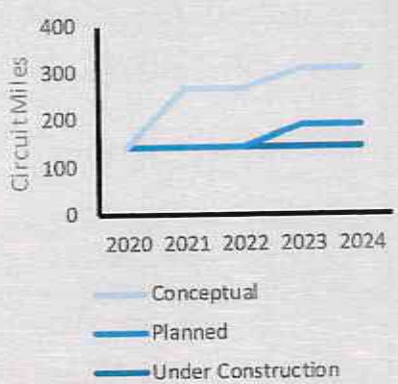
Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and IESO. In accordance with these agreements, planning and operating related issues are discussed and coordinated through respective committees.

Transmission: There are several transmission projects projected to come on-line during the assessment period. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads: transmit power to the export market, improve safety, improve import capability, increase efficiency, and connect new generation. The major system enhancement projects include the addition of a new 500 kV interconnection from Dorsey to Iron Range (Duluth, Minnesota) to come into service in 2020, and the addition of a new 230 kV line from Birtle to Tantallon to come into service in 2021. Some transmission projects have been delayed a few years due to lower than expected load growth in the local area.



MRO-SaskPower

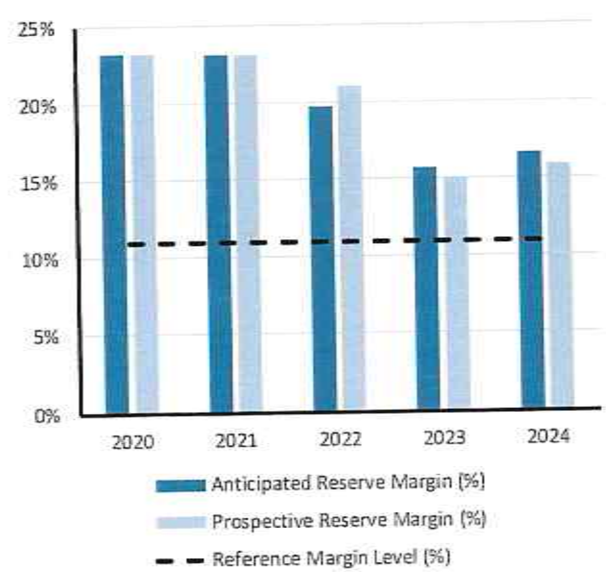
Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections.



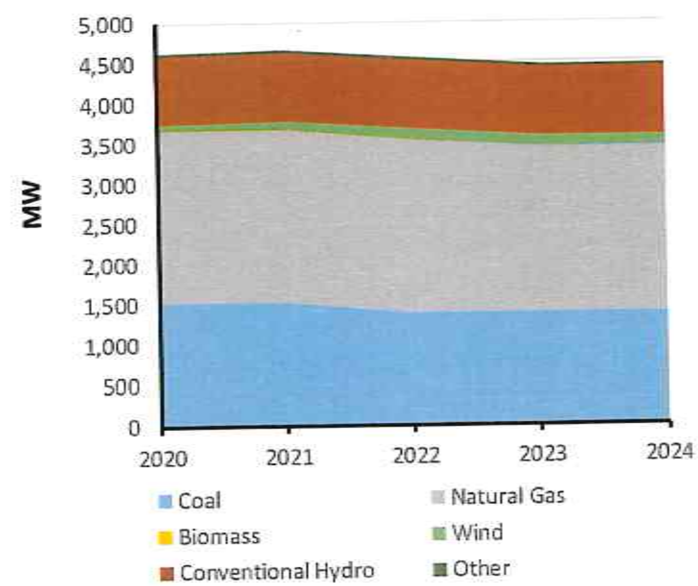
Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)

Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	3,846	3,881	3,923	3,946	3,968	3,930	3,955	3,973	3,995	4,031
Demand Response	85	85	85	85	85	85	85	85	85	85
Net Internal Demand	3,761	3,796	3,838	3,861	3,883	3,845	3,870	3,888	3,910	3,946
Additions: Tier 1	355	390	435	435	435	787	787	787	787	787
Additions: Tier 2	0	0	0	0	0	0	698	698	1,396	1,396
Additions: Tier 3	0	7	7	47	47	47	47	47	87	87
Net Firm Capacity Transfers	125	125	100	100	100	100	100	100	100	100
Existing-Certain and Net Firm Transfers	4,283	4,284	4,163	4,034	4,094	3,948	3,980	3,975	3,824	3,915
Anticipated Reserve Margin (%)	23.32%	23.14%	19.81%	15.75%	16.64%	23.16%	23.19%	22.49%	17.93%	19.16%
Prospective Reserve Margin (%)	23.32%	23.14%	21.14%	15.08%	15.96%	18.86%	36.96%	35.16%	41.11%	42.13%
Reference Margin Level (%)	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Bickett-4

Highlights

- ARMs will remain above the Reference Margin Level (11%) throughout the assessment period.
- Approximately over 1,000 MW of additional renewal capacity is projected over the assessment period.
- A new 230 kV tie line with Manitoba Hydro is under construction to facilitate a 100 MW firm capacity/energy transfer.

SaskPower Fuel Composition

Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Biomass	3	3	3	3	3	3	3	3	3	3
Coal	1,531	1,531	1,531	1,392	1,392	1,392	1,253	1,253	1,253	968
Geothermal		5	5	5	5	5	5	5	5	5
Hydro	862	862	862	862	862	862	862	862	862	862
Natural Gas	2,173	2,173	2,096	2,096	2,351	2,351	2,351	2,351	2,695	2,617
Other	3	3	3	3	3	3	3	3	3	3
Solar		0	0	0	0	0	0	0	0	0
Wind	49	51	86	126	166	204	244	284	324	363
Total	4,620	4,627	4,584	4,485	4,780	4,818	4,719	4,759	5,144	4,820

MRO-SaskPower Assessment

Planning Reserve Margins: SaskPower uses a criterion of 11% as the Reference Reserve Margin for resource adequacy. Saskatchewan has assessed its Planning Reserve Margin for the upcoming ten years while considering the summer and winter peak hour loads, available existing and anticipated generating resources, firm capacity transfers, and DR for each year. Saskatchewan's ARM ranges from approximately 16%–29% and does not fall below the Reference Margin Level.

Demand: SaskPower's system peak forecast is contributed by econometric variables, weather normalization, and individual level forecasts for large industrial customers. Average annual summer and winter peak demand growth is expected to be approximately 1% throughout the assessment period.

Demand-Side Management: SaskPower's EE and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measurable and permanent reductions in electrical energy, and demand reductions during peak hours. Energy provided from EE and demand side management (DSM) programs are modeled as load modifiers and are netted from both the peak load and energy forecasts. A steady growth is expected on EE and conservation over the assessment period. SaskPower's DR program has contracts in place with industrial customers for interruptible load based on defined DR programs. The first of these programs provides a curtailable load, currently up to 85 MW, with a 12-minute event response time. Other programs are in place that provide access to additional curtailable load, requiring up to two hours notification time.

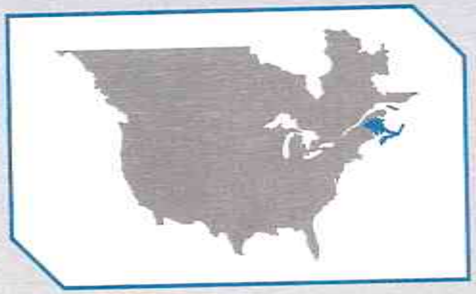
Distributed Energy Resources: The penetration level of DERs is currently very low (approximately 21 MW) therefore SaskPower does not anticipate operational challenges due to the DERs. The current penetration of DER solar PV is approximately 0.8% of the total load. It is estimated that the penetration would increase to approximately 1% in the five-year horizon.

Generation: SaskPower is planning to add a total of 1,146 MW (nameplate capacity) Tier 1 generation, including two 353.5 MW combined-cycle natural gas turbines, 10 MW solar PV, 5 MW geothermal, 387 MW wind, and 37 MW energy power purchase agreement (PPA) with a co-generation partner. SaskPower is planning for a 100 MW of firm import from Manitoba. A total 1,420 MW (nameplate capacity) of Tier 2 capacity additions includes 1,400 MW of combined-cycle natural gas turbines and 20 MW of solar. A total of 552 MW (nameplate capacity) of Tier 3 capacity additions includes 50 MW of solar, 95 MW of flare natural gas, 7 MW biomass project, and 400 MW of wind generation. These additions are being planned to replace capacity retirements and meet emissions target as well as load growth and planning reserve requirements. The addition of future variable resources may require curtailing the resource and having additional fast ramping capacity available from other resources, such as natural gas facilities, to follow the intermittency of the variable resource. SaskPower is not expecting long-term reliability impacts due to increased reliance on natural gas. A total of approximately 501 MW (nameplate capacity) is confirmed for retirements. The confirmed retirements include 25 MW firm import contract expiration with Manitoba Hydro, 278 MW of coal generation, 155 MW of steam generation, 21.2 MW of waste heat recovery generation, and 22 MW of wind generation. The timing of additional coal retirement (284 MW) over the assessment period is still unconfirmed and will be driven by regulatory time line, cost to retrofit with carbon capture technology, and the timing of the new natural gas facility. In addition, unconfirmed retirements also include 123 MW of natural gas facilities. Replacement resources are being planned before the retirements, so SaskPower is not expecting any long-term reliability impacts due to generation retirements.

Capacity Transfers: SaskPower has a contract in place for a firm 25 MW (until March 2022) and a firm 100 MW (starting Summer 2021 and throughout the assessment period) capacity transfers from Manitoba Hydro, including supply source and transmission. A new 230 kV tie-line between Manitoba and Saskatchewan is currently under construction to facilitate the 100 MW capacity transfer. A further capacity transfer of 190 MW from Manitoba is expected to start in Summer 2022. From a capacity and transmission reliability perspective, Saskatchewan has coordinated with Manitoba Hydro to ensure that the capacity transfer is correctly modelled in on-going operational and planning studies. Any planning or operating related issues are coordinated in accordance with the interconnection study agreements through respective planning and operating committees between SaskPower and Manitoba Hydro.

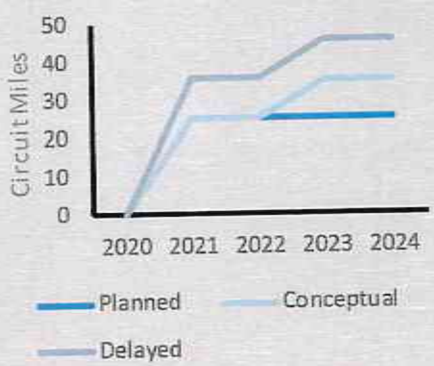
Transmission: SaskPower has several major transmission projects during the 1–5 year planning horizon of the assessment period. These projects are driven by load growth and reliability needs. It has recently completed construction of the three major transmission lines with a total of approximately 270 km of 230 kV and 200 km of 138 kV transmission lines. Approximately 30 km of 230 kV transmission line is under construction, approximately 70 km of 230 kV transmission line is under planning phase, and approximately 195 km of 230 kV line is under conceptual phase.

Exhibit Bickett-4



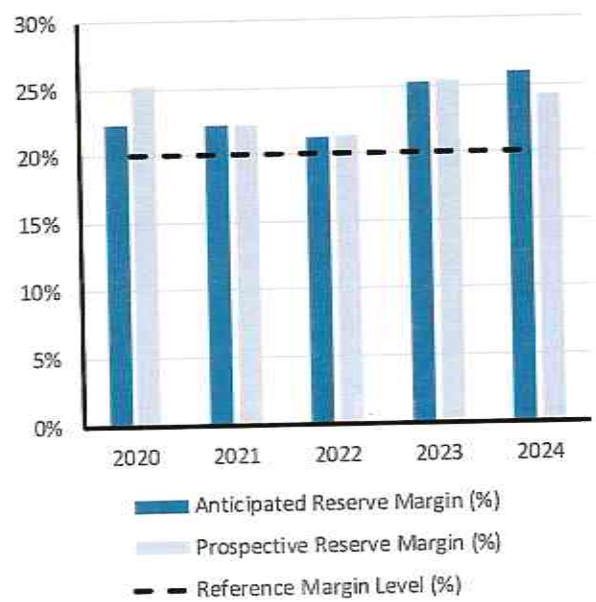
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two BAs. It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI), and Northern Maine (NM), which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million people.

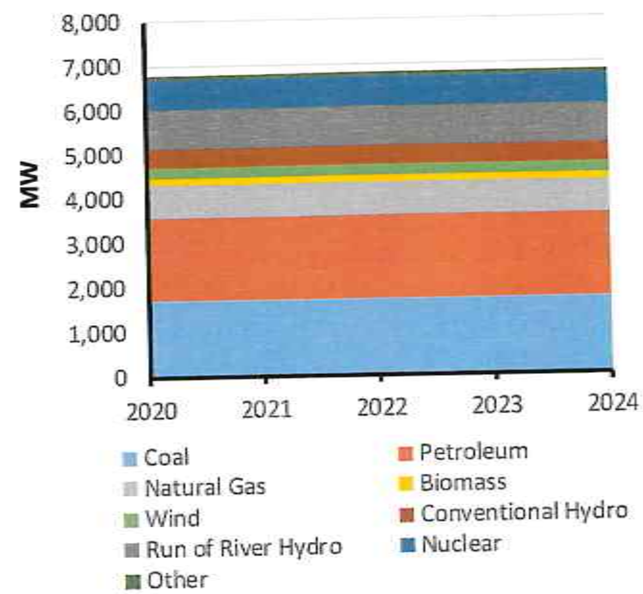


Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)										
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	5,644	5,673	5,664	5,611	5,576	5,541	5,517	5,517	5,501	5,481
Demand Response	277	277	277	277	276	276	276	275	275	274
Net Internal Demand	5,367	5,396	5,388	5,335	5,300	5,265	5,242	5,241	5,226	5,207
Additions: Tier 1	5	27	50	50	50	50	50	50	50	50
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	9	9	9	9	9	9	9	9	9	9
Net Firm Capacity Transfers	-69	-66	-149	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	6,565	6,568	6,485	6,632	6,630	6,630	6,630	6,520	6,518	6,518
Anticipated Reserve Margin (%)	22.41%	22.21%	21.29%	25.26%	26.03%	26.87%	27.44%	25.35%	25.67%	26.13%
Prospective Reserve Margin (%)	25.26%	22.31%	21.38%	25.35%	24.28%	24.57%	19.60%	17.51%	17.81%	18.24%
Reference Margin Level (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Beckett-4

Highlights

- Demand growth is effectively negligible over the duration of the *2019 LTRA* analysis period. Any growth in demand has been offset by load reductions from demand-side management.
- The Maritimes Link, an undersea high-voltage direct current (HVDC) undersea cable connection to the Canadian province of Newfoundland and Labrador, began service in late 2017. This will allow for the mid-2020 retirement of a 153 MW coal-fired generator with an equivalent amount of firm hydro capacity imported through the link so that the overall resource adequacy is unaffected.

Maritimes Fuel Composition

Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695
Petroleum	1,858	1,858	1,876	1,875	1,872	1,872	1,872	1,872	1,870	1,870
Natural Gas	760	760	760	760	760	760	760	760	760	760
Biomass	153	153	153	153	153	153	153	153	153	153
Wind	209	222	227	227	227	227	227	227	227	227
Conventional Hydro	444	444	444	444	444	444	444	444	444	444
Run of River Hydro	902	902	902	902	902	902	902	792	792	792
Nuclear	660	660	660	660	660	660	660	660	660	660
Other	90	90	90	90	90	90	90	90	90	90
Total MW	6,771	6,784	6,807	6,805	6,803	6,803	6,803	6,693	6,691	6,691

Exhibit Bickett-4

NPCC-Maritimes Assessment

Planning Reserve Margins: The reference Reserve Margin Level used for evaluating the NB, NS, PEI, and NM subareas comprising the Maritimes area is 20%. Existing certain and net-firm transfers and ARMs in the area do not fall below that level at any time during the 10-year assessment period of this *2019 LTRA* analysis. The Prospective Reserve Margins in the years 7 to 10 of the LTRA period range from 17.5%–19.6% as uncertain retirements occur with no replacement supply contracts currently in place to provide an offset. Anticipated replacement contracts or deferral of uncertain retirements will occur to meet the 20% reference level in Years 7 to 10.

Demand: There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest subareas that are historically highly coincidental (typically 97%–99%). Demand is determined to be the non-coincident sum of the peak loads forecasted by the individual subareas. The aggregated growth rates of both demand and energy for the combined subareas are practically flat over summer or winter seasonal periods of the LTRA assessment period. Peak loads are expected to increase by 1.5% during summer but decline by 3.6% during winter seasons over the 10-year assessment period. This translates to average growth rates of 0.1% in summer and -0.4% in winter. Annual energy forecasts are expected to increase by a total of 0.3% during the 10-year assessment period for an average growth of 0.03% per year. Rural to metropolitan population migration and the introduction of split-phase heat pump technology to areas traditionally heated by fossil fuels has created load growth for the southeastern corner of the NB that has outpaced load growth in the rest the Maritimes area in recent years. It is expected that these effects will level off in the future.

Demand-Side Management: Plans to develop up to 120 MW by 2029–2030 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway, but no specific annual demand and energy saving targets currently exist. During the assessment period, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 9 MW to 127 MW while the annual amounts for winter peak demand reductions rise from 72 MW to 632 MW.

Distributed Energy Resources: The current amount of distributed energy resources in the Maritimes area is currently insignificant at about 17 MW in winter. During the *2019 LTRA* period, additions of solar (mainly rooftop) resources in NS are expected to increase this value to about 215 MW. It is assumed that the capacity contribution during the peak is zero as generation occurs at times non-coincident with system peak (winter evenings). As more installations are phased in, operational challenges, such as ramping and light load conditions, will be considered and mitigation techniques will be investigated.

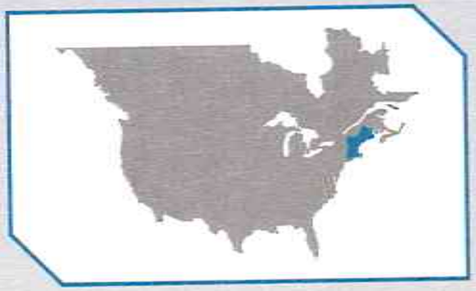
Generation: Several small generators (about 90 MW aggregated) are scheduled to retire in NM and PEI during the 10-year LTRA analysis period. In NB, retirement of about 390 MW of natural-gas-fired generation and a further 28 MW petroleum fueled resource may happen as early as 2028 if sufficient load reductions from its internal reduce and shift demand programs occur to reliably allow their removal. NS will retire a 150 MW coal-fueled generator in 2020, provided capacity from the Muskrat Falls hydro-electricity project in the Canadian province of Newfoundland and Labrador are available to offset its removal.

Small amounts of new generation capacity are being installed to introduce alternative renewable energy resources into the capacity mix. Except for hydro generation, renewable electricity standards (RESs) have led to the development of substantially more wind generation capacity than any other renewable generation type. In NS, the RES target for 2019 calls for 25% of energy sales to be supplied from renewable resources. This target increases to 40% of energy sales from renewable resources in 2020. Currently the 25% target is being met primarily by wind generation, hydro, and biomass. For wind capacity, NPCC-Maritimes applies year-round calculated equivalent capacities of 22% (NB), 17% (NS), 15% (PEI), and 40% (NM) of nameplate.

Capacity Transfers: Probabilistic studies show that the Maritimes area is not reliant on interarea capacity transfers to meet NPCC resource adequacy criteria.

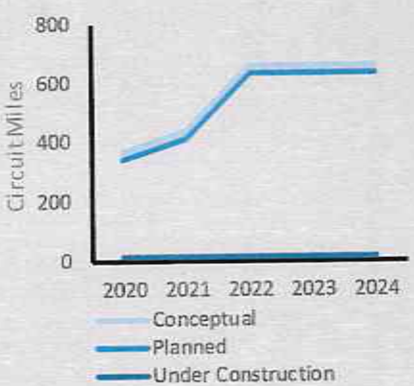
Transmission: Construction of a 475 MW +/-200 kV HVDC undersea cable link (Maritime Link) between Newfoundland and Labrador and NS was completed in late 2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 150 MW (nameplate) coal-fired unit in NS by mid-2020. This unit will only be retired once a similarly sized replacement firm capacity contract from Muskrat Falls is in operation so that the overall resource adequacy is unaffected by these changes. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB area.

Exhibit Bickett-4



NPCC-New England

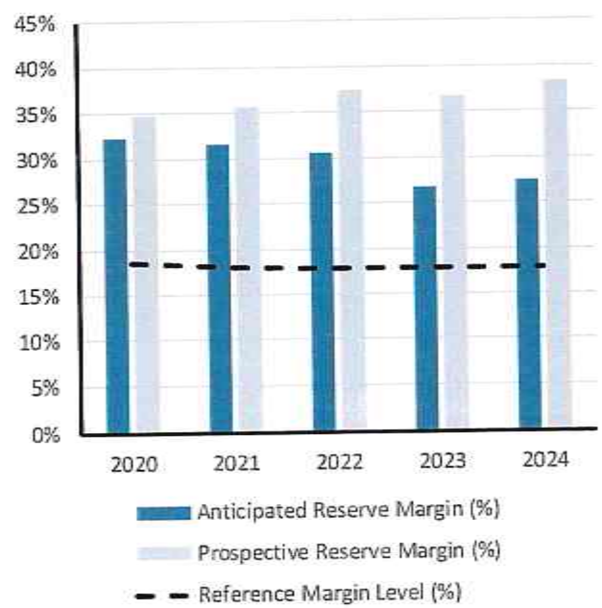
ISO New England (ISO-NE) Inc. is a regional transmission organization that serves Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO-NE is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.



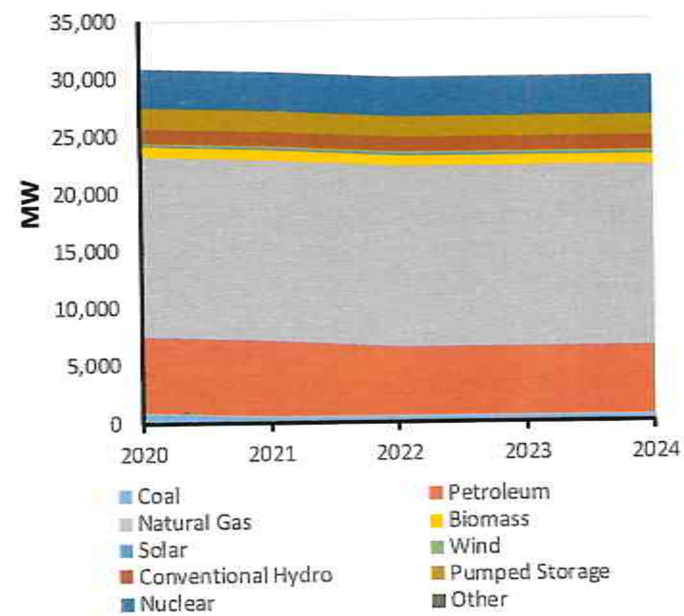
Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)

Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	25,025	24,793	24,620	24,479	24,383	24,329	24,315	24,341	24,408	24,476
Demand Response	441	613	686	686	686	686	686	686	686	686
Net Internal Demand	24,584	24,180	23,934	23,793	23,697	23,643	23,629	23,655	23,722	23,790
Additions: Tier 1	111	159	252	252	252	252	252	252	252	252
Additions: Tier 2	71	427	1,100	1,854	2,065	2,329	2,329	2,329	2,329	2,329
Additions: Tier 3	539	1,085	1,587	3,825	3,872	3,978	4,543	4,543	4,543	4,543
Net Firm Capacity Transfers	1,622	1,247	1,188	81	81	81	81	81	81	81
Existing-Certain and Net Firm Transfers	32,399	31,676	30,991	29,899	29,925	29,943	29,957	29,969	29,979	29,991
Anticipated Reserve Margin (%)	32.24%	31.66%	30.53%	26.72%	27.34%	27.71%	27.84%	27.75%	27.44%	27.12%
Prospective Reserve Margin (%)	34.69%	35.61%	37.32%	36.72%	38.27%	39.78%	39.92%	39.82%	39.47%	39.12%
Reference Margin Level (%)	18.50%	18.00%	17.80%	17.80%	17.80%	17.80%	17.80%	17.80%	17.80%	17.80%



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Bickett-4

Highlights

The results of ISO-NE's 2019 NERC LTRA show the following:

- New England has the resource base and transmission system needed to meet consumer demand for power during the study period.
- ISO New England has implemented near-term market and operational changes to address the Region's energy-security risks while also discussing long-term market solutions with regional stakeholders.
- New England has implemented solutions that include enhancing operating procedures for confirming natural gas availability, improving communications and coordination with natural gas pipeline operators, and implementing a 21-day energy emergency forecast to address the fuel security issue.
- Market-based solutions, currently under development, should promote additional fuel-supply chain measures, including firm contracts with natural gas supply and transmission to improve natural gas availability for power generation, the use of existing and new dual-fuel capability when natural gas supplies are limited, and adequate on-site storage and replenishment of liquid fuels to enhance dual-fuel power plant availability and reliability.
- The development of renewable resources, EE and conservation, and expanded power imports combined with the continued investment in natural gas sector efficiency measures will help New England mitigate the identified fuel security risks.

New England Fuel Mix

Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	914	531	531	531	531	531	531	531	531	531
Petroleum	6,519	6,519	5,937	5,937	5,937	5,937	5,937	5,937	5,937	5,937
Natural Gas	15,795	15,795	15,801	15,801	15,801	15,801	15,801	15,801	15,801	15,801
Biomass	932	932	929	929	929	929	929	929	929	929
Solar	41	80	105	105	105	105	105	105	105	105
Wind	163	171	171	171	171	171	171	171	171	171
Conventional Hydro	1,282	1,281	1,286	1,286	1,286	1,286	1,286	1,286	1,286	1,286
Pumped Storage	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854
Nuclear	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323
Other	5	5	5	5	5	5	5	5	5	5
Total MW	30,828	30,492	29,942	29,942	29,942	29,942	29,942	29,942	29,942	29,942

NPCC-New England Assessment

Planning Reserve Margins: ISO-NE's Reference Margin Level is based on the capacity needed to meet the NPCC one day in 10 years LOLE resource planning reliability criterion. The capacity needed, referred to as the ICR, varies from year-to-year depending on projected system conditions (e.g., demand, generation, transmission, imports). The ICR is calculated on an annual basis, four years in advance for each forward capacity market auction, and results in a Reference Margin Level of 18.4% in 2019, 18.5% in 2020, and 18.0% in 2021 as expressed in terms of the 50/50 peak demand forecast published in May 2019. In this LTRA, the last calculated Reference Margin Level (17.8%) is applied for the remaining seven years of this LTRA forecast. ISO-NE's ARM is expected to stay above the Reference Margin Level during the assessment period.

Demand: ISO-NE develops an independent demand forecast for its BA area by using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and state's demand forecast is considered coincident. This demand forecast is the gross demand forecast. Annually, ISO-NE also forecasts the load reduction impact of BTM solar PV resources, and the reductions to peak demand and energy due to passive demand response programs that are comprised mostly of EE. EE in 2019 is 2,913 MW and is forecast to grow to 3,706 MW by 2021 and increase to over 5,370 MW by 2028. Nameplate BTM solar PV in 2019 is 2,011 MW and is forecast to grow to 2,589 MW by 2021 and increase to 4,185 MW by 2028. The BTM solar PV and EE forecasts are seen as reductions (net demand forecast) to the gross demand forecast.

ISO-NE is a summer-peaking electrical power system. The reference demand forecast is based on the reference economic forecast, which reflects the regional economic conditions that are expected to occur. Both the summer peak TID and the NEL are forecast to decrease from 2019 to 2028. The TID decreases from 25,323 MW in 2019 to 24,408 MW in 2028. This amounts to a 9-year summer TID CAGR of -0.4%. The NEL is expected to decrease from 125,823 GWh in 2019 to 121,336 GWh in 2028, amounting to an energy CAGR of -0.4%.

Demand-Side Management: On June 1, 2018, ISO-NE integrated price-responsive DR into the energy and reserve markets. Approximately 408 MW of DR participates in these markets and is dispatchable (i.e., treated similar to generators). Because of these changes, DR is no longer to be considered an "emergency resource" that is dispatched during actual of forecast capacity deficiencies under system operator emergency operating procedures. Within ISO-NE's ICR calculations, DR availability is based on historical DR performance from the past five years. The summer performance of DR was 94% and the winter performance was 95%.

Distributed Energy Resources: New England has 160 MW (1,390 MW nameplate) of wind generation and 440 MW (1,206 MW nameplate) of BTM solar PV. Approximately 10,950 MW (nameplate) of wind generation projects have requested generation interconnection studies. BTM solar PV is forecast to grow to 1,051 MW (4,185 MW nameplate) by 2028. The BTM solar PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages, which include the effect of diminishing solar PV production at time of the system peak as increasing solar PV penetrations shift the timing of peaks later in the day, decrease from 35.2% of nameplate in 2019 to about 25.1% in 2028.

Generation: Generating capacity that has been added since the *2018 LTRA* consists primarily of 860 MW nameplate of CC and GT units. Existing certain capacity for 2019 is 30,602 MW. A total of ~1,093 MW of Tier 1 gas-fired capacity is projected to be added by 2022. Tier 2 capacity additions scheduled for 2021 include 2,039 MW of gas-fired, solar, and wind generation. In 2024, scheduled Tier 2 capacity additions total 6,148 MW nameplate of the same types of technologies.

The combination of constrained natural gas pipelines during winter, indeterminate LNG and fuel oil deliveries, and upcoming planned retirements of nuclear and non-natural-gas-fired generation, has prompted ISO-NE to undertake an operational fuel security analysis. This new reliability analysis that focuses on winter operations has predefined electric and natural gas sector topology and fuel supply assumptions that are used to gauge the impact that certain prolonged regional fuel infrastructure outages have upon BPS reliability. To address reliability issues relating to fuel/energy security, FERC directed ISO New England to file tariff revisions by August 31, 2018, to address fuel security concerns in the near term and by July 1, 2019, to address fuel security concerns over the long term.

Capacity Transfers: New England is interconnected with the three BAs of Quebec, Maritimes, and New York. ISO-NE takes into account this transfer capability to assure that their limits do not impact regional resource adequacy. ISO-NE's FCM methodology limits the purchase of import capacity based on the interconnection transfer limits. ISO-NE's capacity imports are assumed to range from 1,428 MW to 1,188 MW during the 2019 to 2022 period and decreasing to 81 MW for the remainder of the LTRA years since FCM has only secured resources through the 2022 period.

Transmission: There are a number of new projects planned and under construction that are needed to maintain transmission reliability; the most significant area of concern is Boston. The Greater Boston transmission project has addressed many of these concerns, and most of the project is expected to be in service by December 2019 with the last component possibly delayed until June 2021. The second area that remains

Exhibit Bickett-4

a significant concern is the SEMA/RI area. This area has both import constraints and significant constraints on moving power within the area. Similar to the Boston area, system operators will be reliant on the out-of-merit dispatch of local resources and system reconfigurations to meet system needs. Solutions to address these time sensitive operational needs in the Southeast Massachussetts and Rhode Island areas have been developed.

Transmission reliability needs in the Greater Hartford–Central Connecticut area are being addressed with projects that are under construction or already in service. Projects to address reliability needs in Southwest Connecticut that are closely linked to the Greater Hartford-Central Connecticut project are also under construction or already in service. The Maine Power Reliability Program added significant 345 kV infrastructure that has already been completed and other parts of the project are now under construction and expected to be in service by November 2018. In the past, New Hampshire and Vermont had been studied together. Reliability upgrades needed in Vermont are under construction. The New Hampshire portion upgrades are predominantly 115 kV and based within the Seacoast Region with an anticipated in-service date of December 2019. In Western Massachusetts, a suite of reliability-based projects is almost complete in the Pittsfield/Greenfield area.

The electric power system in New England is undergoing a major transition. The owners of traditional power plants—nuclear, coal, and oil-fired—are permanently closing many of these stations due to economic and environmental pressures. The majority of the Region's electricity, both currently and for the foreseeable future, is likely to come from newer, more efficient natural-gas-fired generation and an array of renewable energy technologies, such as solar and wind powered generation. Both renewable and natural-gas-based generation technologies rely on the "just-in-time" delivery of their energy sources. Solar- and wind-based power inherently vary with the weather. Less obvious and of greater concern is the just-in-time delivery of natural gas from several interstate natural gas pipelines to the Region's natural-gas-fired generating stations. During cold winter conditions, these natural gas pipelines rapidly reach full capacity with natural gas targeted for the space heating needs by natural gas utility (firm) customers and are unable to fuel many of New England's power plants.

New England is currently fuel constrained, and this has been identified as the greatest "reliability risk" to the area. Combined with the constrained gas pipelines during winter, the following factors have exacerbated the situation:

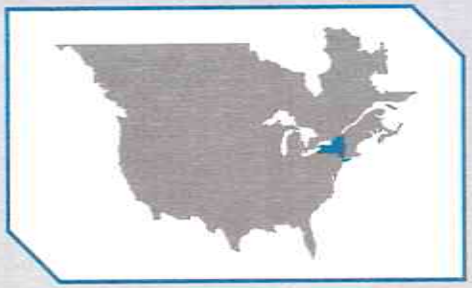
- VERs (i.e., intermittent wind, solar, and hydro-electric resources) and natural-gas-fired generators with infrastructure and operational limitations on their energy production are replacing traditional nuclear, coal, and oil-fired resources that have the capability to stockpile their fuel on-site.
- Although new, incremental natural-gas-fired generation is being added to the fuel mix, the regional gas pipelines continue to have limited fuel deliverability for any power generators without firm natural gas transportation contracts.
- LNG deliveries to New England, which mandates importing foreign LNG due to Jones Act restrictions, are influenced by global economics and maritime transportation logistics. Importing LNG is uncertain without predefined firm supply contracts.
- Environmental permitting for new dual-fuel capability (typically, natural gas and fuel oil) is becoming more difficult under ever tightening state and federal air emissions regulations. Even when these units are granted permits, their run times for burning fuel oil are usually restricted to limit their overall ozone season (May 1–September 30) air emissions.

Giving the heightened priority to the regional fuel/energy security issue, FERC directed ISO New England to submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[36] That directive arose amidst a contentious regulatory process involving shorter-term, out-of-market actions to bolster the Region's (winter) fuel supplies by delaying the retirement of the large Mystic Generating Station in Everett, Massachusetts. This station is fueled solely by vaporized LNG from the Distrigas LNG Import Terminal located on the Mystic River, in Everett, Massachusetts.

In response to the FERC directive and to address regional energy security issues, ISO New England and its stakeholders are working to develop a new, three-part market based approach: a multi-day ahead market, new ancillary services, and seasonal forward procurement, all scheduled for implementation in the 2024–2025 time frame.

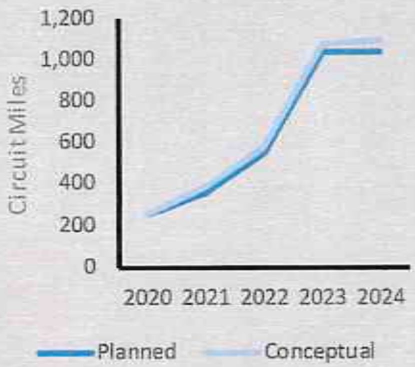
36 ISO New England Inc., 164 FERC 61,003 at PP 2,5 (2018)

Exhibit Bickett-4



NPCC-New York

The New York Independent System Operator (NYISO) is the only BA within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the investor-owned utilities and public power authorities—in 1999. NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines and serves the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.



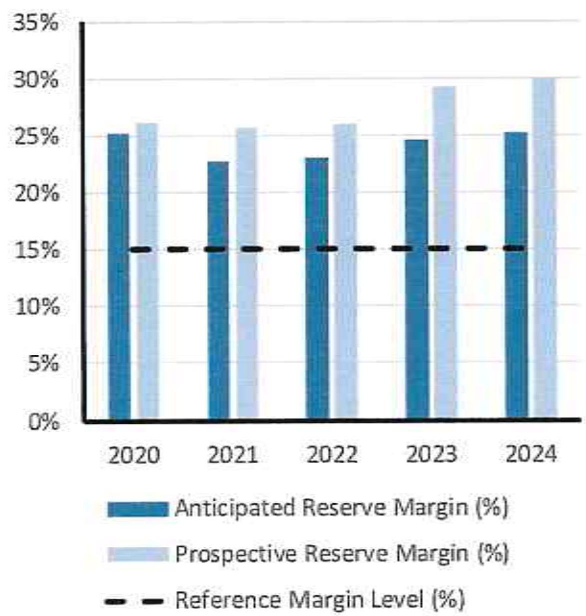
Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)

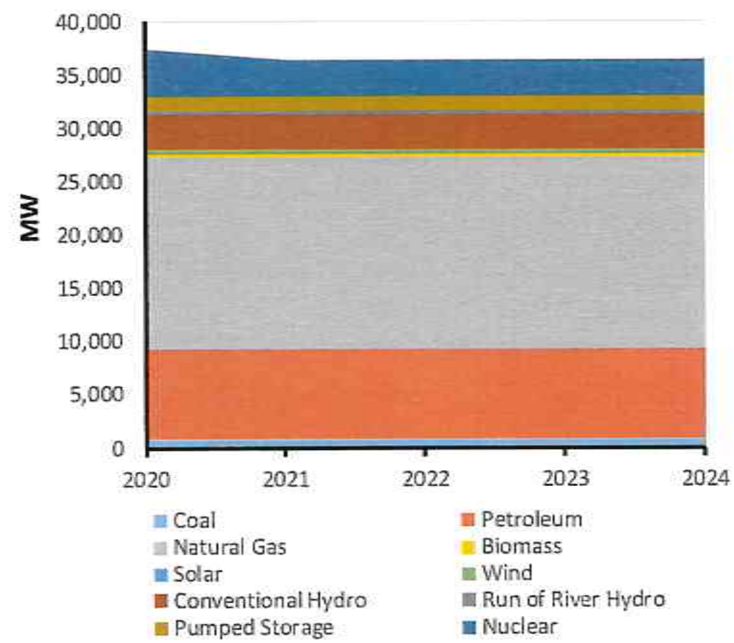
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	32,202	32,063	31,971	31,700	31,522	31,387	31,246	31,121	31,068	31,115
Demand Response	904	904	904	904	904	904	904	904	904	904
Net Internal Demand	31,298	31,159	31,067	30,796	30,618	30,483	30,342	30,217	30,164	30,211
Additions: Tier 1	1,133	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170	1,170
Additions: Tier 2	283	928	928	1,436	1,436	1,436	1,436	1,436	1,436	1,436
Additions: Tier 3	1,169	2,376	2,974	4,428	5,613	5,613	5,613	5,613	5,613	5,613
Net Firm Capacity Transfers	1,783	1,797	1,801	1,939	1,939	1,939	1,939	1,939	1,939	1,939
Existing-Certain and Net Firm Transfers	38,075	37,051	37,055	37,193	37,193	37,193	37,193	37,193	37,193	37,193
Anticipated Reserve Margin (%)*	25.27%	22.66%	23.04%	24.57%	25.29%	25.85%	26.43%	26.96%	27.18%	26.98%
Prospective Reserve Margin (%)	26.17%	25.64%	26.03%	29.23%	29.98%	30.56%	31.17%	31.71%	31.94%	31.74%
Reference Margin Level (%)**	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%

*Values with derated MW values for wind, solar, and run-of-river hydro

**The NERC LTRA Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an installed reserve margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The New York State Reliability Council approved the 2019–2020 IRM at 17.0%.



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Bickett-4

Highlights

- The 2018–2019 reliability planning process finalized its second phase (i.e., the 2019–2028 Comprehensive Reliability Plan (CRP)) in July 2019. The CRP confirmed the 2018 reliability needs assessment's findings that there are no reliability needs throughout the 10-year study period (2019–2028). The base case assumptions include the retirement of over 3,600 MW, including the Indian Point Energy Center (IPEC), and the addition of over 2,300 MW of new supply resources.
- The CRP also includes, for information only and not action, a scenario assessment of the impacts to system reliability from the potential deactivation of all generators impacted by the New York State Department of Environmental Conservation's proposed rulemaking to control oxides of nitrogen emissions from simple cycle and regenerative combustion turbines (Peaker Rule). The rule may impact approximately 3,300 MW (nameplate) of simple cycle combustion turbines, mostly located in New York City (Zone J) and Long Island (Zone K), by 2025. For this scenario, the remaining coal plants in New York state were assumed to be retired based upon the New York State Department of Environmental Conservation rule setting carbon dioxide emission requirements for existing fossil-fueled generators. The simulation identified a system-wide resource adequacy deficiency and transmission security load pocket deficiencies in New York City and Long Island.
- The ten-year annual average energy and demand projections are continuing to decline. The baseline forecast includes upward adjustments for usage of electric vehicles and downward adjustments for the impacts of EE trends, distributed energy resources, storage, and BTM solar PV.
- The NYISO Board of Directors selected projects under two public policy transmission planning processes, one for Western New York and second for Central New York and the Hudson Valley, which is known as the ac transmission need. When completed, these projects will add more transfer capability in Western New York and also between upstate and downstate New York.
- Demand and consumption in NY are heavily influenced by state EE and renewable energy public policy programs, such as the Clean Energy Standard, which aims to produce 70% of state-wide energy consumption from renewable resources by 2030.

New York Fuel Mix										
Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	837	837	837	837	837	837	837	837	837	837
Petroleum	8,387	8,387	8,387	8,387	8,387	8,387	8,387	8,387	8,387	8,387
Natural Gas	18,067	18,086	18,086	18,086	18,086	18,086	18,086	18,086	18,086	18,086
Biomass	321	321	321	321	321	321	321	321	321	321
Solar	26	26	26	26	26	26	26	26	26	26
Wind	296	314	314	314	314	314	314	314	314	314
Conventional Hydro	3,322	3,322	3,322	3,322	3,322	3,322	3,322	3,322	3,322	3,322
Run of River Hydro	375	375	375	375	375	375	375	375	375	375
Pumped Storage	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411
Nuclear	4,384	3,346	3,346	3,346	3,346	3,346	3,346	3,346	3,346	3,346
Total MW	37,424	36,424	36,424	36,424	36,424	36,424	36,424	36,424	36,424	36,424

NPCC-New York Assessment

Planning Reserve Margins: The NYISO provides significant support to the New York State Reliability Council (NYSRC) that conducts an annual installed reserve margin (IRM) study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC resource adequacy criterion of a LOLE of no greater than 0.1 days per year. The IRM for the 2019–2020 capability year (May 1 through April 30) is 17% of the forecasted NYCA peak load—all values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15%–18.2%. Also, the NYISO is forecasting adequate installed capacity to meet the 0.1 days per year LOLE for all ten years of the *Reliability Needs Assessment* (2019–2028).

Demand: The peak load forecast is based upon a model that incorporates forecasts of economic drivers, end use and technology trends, and normal weather conditions. The NYISO incorporates the impacts of EE and technology trends directly into the forecast model with additional adjustments for distributed energy resources, electric vehicles, and BTM solar PV. The baseline forecast includes upward adjustments for increased usage of electric vehicles and downward adjustments for the impacts of EE trends, storage, distributed energy resources, and BTM solar PV. The ten-year annual average energy growth rate is lower than last year (-0.27% per year in 2019 versus -0.14% in 2018). The 10-year annual average summer peak demand growth rate is lower than last year (-0.39% per year in 2019 versus -0.13% in 2018).

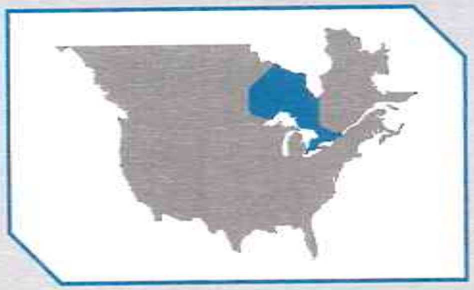
Demand-Side Management: The NYISO's planning process accounts for DR resources that participate in the NYISO's reliability-based DR programs based on the enrolled MW derated by historical performance. For 2019, the DR participation for the summer capability period has increased slightly to 1,315 MW. There are 116.5 MW of DR participating in ancillary services programs that provide 10-minute spinning reserves.

Distributed Energy Resources: The NYISO published a report in February 2017 providing a roadmap that will be used over the next three to five years as a framework to develop the market design elements, functional requirements, and tariff language necessary to implement the NYISO's vision to integrate DERs into NYISO's energy, ancillary services, and capacity markets. The NYISO also published a market design concept paper in December 2017 and is currently in the process of implementing the market design of this initiative. BTM solar PV are currently being addressed operationally in the day-ahead and real-time load forecasts. A solar forecasting system to integrate with the day-ahead and real-time markets was implemented in 2017. In April 2019, NYISO stakeholders approved the market design and the proposed tariff changes. The NYISO is currently in the process of preparing to file the tariff changes with FERC and also preparing to implement the DER participation model in 2021.

Generation: The NYISO completed a *Generator Deactivation Assessment* in 2017 regarding the deactivation of the Indian Point Energy Center Unit Nos. 2 and 3 (approximately 2,150 MW total in 2020 and 2021, respectively) that concluded that no generation deactivation reliability needs arise. The NYISO's 2018 reliability planning process includes approximately 2,300 MW of proposed generation, including the 680 MW CPV Valley Energy Center, which entered into service in 2018, and the 1,020 MW Cricket Valley Energy Center, which is expected to enter into service in 2020.

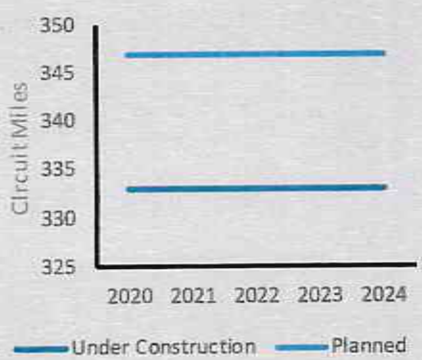
Capacity Transfers: The models used for the NYISO planning studies include the firm capacity transactions (purchases and sales) with the neighboring systems as a base case assumption. The net MW seasonal values are also published in the NYISO's *Gold Book* and include the yearly election of the unforced capacity deliverability rights and other firm capacity transactions made via the applicable processes.

Transmission: The 2018–2019 reliability planning process includes proposed transmission projects, including the NextEra's Empire State Line project selected under the Western NY Public Policy Transmission Planning Process, and transmission owner LTPs that have met the Reliability Planning Process inclusion rules. The NYISO Board of Directors also selected projects under the AC Transmission (2019) public policy processes. When completed, these projects will add more transfer capability in Western New York and also between upstate and downstate New York.



NPCC-Ontario

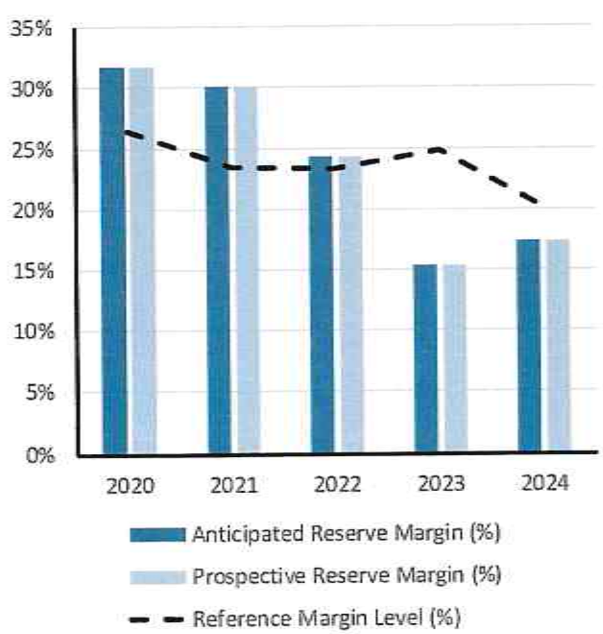
The Independent Electricity System Operator (IESO) is the BA and Reliability Coordinator for the province of Ontario. In addition to administering the area's wholesale electricity markets, the IESO plans for Ontario's future energy needs. The province of Ontario covers more than 415,000 square miles and has a population of more than 14 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.



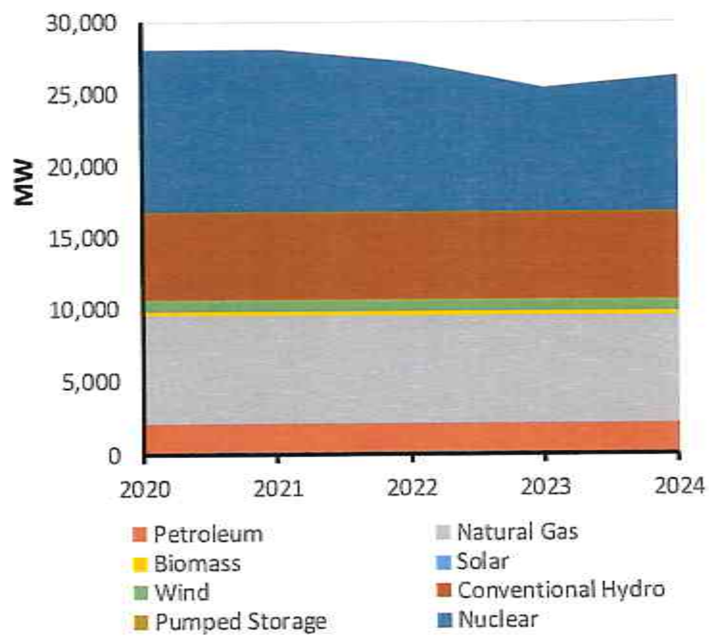
Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)

Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	22,094	22,372	22,649	22,819	23,128	23,307	23,195	23,289	23,723	24,186
Demand Response	794	794	794	794	794	794	794	794	794	794
Net Internal Demand	21,300	21,577	21,855	22,025	22,333	22,513	22,401	22,495	22,928	23,392
Additions: Tier 1	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	27,059	27,059	26,174	24,386	25,192	23,243	24,080	24,080	24,014	24,834
Anticipated Reserve Margin (%)	31.78%	30.09%	24.39%	15.31%	17.32%	7.73%	12.00%	11.54%	9.14%	10.49%
Prospective Reserve Margin (%)	31.78%	30.09%	24.39%	15.31%	17.32%	7.73%	12.00%	11.54%	9.14%	10.49%
Reference Margin Level (%)	26.39%	23.43%	23.30%	24.75%	20.07%	19.07%	23.40%	21.53%	21.58%	21.70%



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Birkett-4

Highlights

- Projected reserve margin shortfalls in the later part of the LTRA horizon are a reflection of nuclear retirements and refurbishments and expiration of supply contracts.
- The DR auction is evolving into a broader and more competitive capacity acquisition mechanism to acquire off-contract resources and address capacity needs.
- Integration of distributed energy resources and changing demand and supply patterns are creating new operating challenges in managing the BPS while providing greater customer choice and opportunity to optimize grid reliability services. The IESO collaborates with local distribution companies to ensure it has visibility of their operations and is able to forecast their output over different time frames, study their impact on reliability, and coordinate their operations to ensure reliability.
- Several transmission projects are under development to enhance the reliability of the BPS and connect growing agricultural loads in the southwest of the province.

Ontario Fuel Composition										
Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Petroleum	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114
Natural Gas	7,435	7,435	7,429	7,435	7,435	7,429	7,435	7,435	7,429	7,435
Biomass	302	302	302	302	302	302	302	302	302	302
Solar	66	66	66	66	66	66	66	66	66	66
Wind	666	666	666	666	666	666	666	666	666	666
Conventional Hydro	6,107	6,107	6,107	6,107	6,107	6,107	6,107	6,107	6,107	6,107
Pumped Storage	120	120	120	120	120	120	120	120	120	120
Nuclear	11,258	11,258	10,380	8,585	9,391	7,449	8,279	8,279	8,221	9,033
Total MW	28,069	28,069	27,185	25,396	26,202	24,253	25,090	25,090	25,025	25,844

Exhibit Bickett-4

NPCC-Ontario Assessment

Planning Reserve Margins: The ARMs fall below the Reference Margin level in the mid-2020s. This is driven by nuclear retirements and the nuclear refurbishment program with the assumption that certain generation resources are not available once their generation contracts have expired. In calculating reserve margins, the IESO does not consider controlled actions or operating procedures in its adequacy assessments. The IESO is evolving its DR auction to include additional resource types, such as off-contract generators, storage, and imports into future capacity auctions to address supply needs in advance of 2023 and beyond. Other options include coordinating outages outside peak load seasons or periods of potential capacity shortages, the potential for more conservation, uprates to existing facilities, and consideration of non-firm imports.

Demand: Demand will experience gradual upward pressure from economic and demographic growth. At the same time, structural changes in Ontario's economy are changing its composition from an energy-intensive industrial economy to one that is more service-oriented. Further, the current provincially funded energy conservation programs are scheduled to end at the end of 2020. In Southwestern Ontario, expansion of the greenhouse and floriculture sector due to the move to year-round vegetable growth and, to a lesser extent, the legalization of cannabis, is expected to double the electricity demand in the Windsor-Essex area over the next five years. These combined factors translate into an overall increase in energy demand over the forecast horizon.

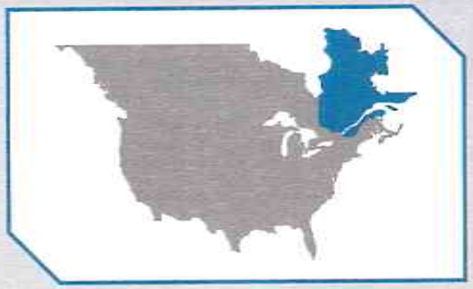
Demand-Side Management: Ontario has two DR programs: dispatchable loads and capacity auction acquired DR. The IESO's Demand Response Working Group works with providers to evolve DR in the IESO-administered markets, including improving the utilization of DR in real time operations. The December 2018 DR auction procured 818.4 MW for the six-month summer commitment period beginning on May 1, 2019, and 854.2 MW for the six-month winter commitment period beginning on November 1, 2019.

Distributed Energy Resources: The IESO estimates total DERs in Ontario exceed 4,300 MW, including over 3,400 MW of contracted resources. The IESO continues to collaborate with the DER community to enhance the reliability and efficiency of Ontario's electricity grid. Although the output from DERs has plateaued, the need for more flexible generation to manage variability remains. Given that DERs are challenging to forecast, it can be difficult to efficiently commit non-quick-start resources or schedule transactions on the interties to manage supply and demand. Currently, to manage this variability, the IESO is initiating control actions such as committing dispatchable generation and curtailing intertie transactions.

Generation: Retirement of the Pickering Nuclear Generating Station (total capacity of approximately 3,000 MW) is expected by 2024. Nuclear refurbishments at Bruce and Darlington generating stations will reduce the generation capacity available over peak seasons. Ontario expects to add about 1,490 MW of new resources to the grid by 2020, including about 460 MW of wind, 900 MW of natural-gas-fired generation, 30 MW of hydroelectric, and 100 MW of solar. Substantial resource turnover is anticipated in the coming years that is driven by nuclear retirements, nuclear refurbishments, and the expiry of contracted resources. The availability of the nuclear fleet is a major resource turnover risk that requires additional attention.

Capacity Transfers: As part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. Ontario has the option to receive 500 MW of capacity from Quebec for one summer before 2030.

Transmission: A new 400–450 km long 230 kV double-circuit transmission line (the East–West Tie) is planned to come into service in 2021 to reinforce the connection of Northwestern Ontario to the rest of the provincial grid providing reliable and cost-effective long-term supply to this area. In the Sudbury area, development work has been initiated to unbundle a double circuit in order to address the situation when one of the existing circuits is initially out of service and the loss of the companion circuit may result in voltage collapse in the local area. Planning is underway to reinforce the 230 kV transmission lines between Richview Transformer Station (TS) and Manby TS by 2023 to increase the supply capability into the Central Toronto area. In the Windsor–Essex area, two projects have been initiated: development of a new switching station at Leamington Junction to sectionalize and switch the four existing 230 kV circuits from Chatham to the Windsor area, expected in-service in the fourth quarter pf 2022; a new approximately 50-km double-circuit 230 kV transmission line to bring additional supply to the area by the fourth quarter of 2025. In the Ottawa area, a project has been initiated to upgrade circuits between Merivale TS and Hawthorne TS with a planned in-service date of December 2022. This project will address supply capacity constraints to West Ottawa and support the deliverability of capacity imports from Québec. Other system improvements that have been planned or are under study include the installation of 500 kV line-connected shunt reactors in Eastern Ontario to mitigate high system voltages under low demand/low transfer periods.

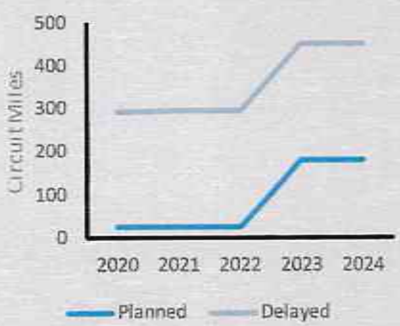


NPCC-Québec

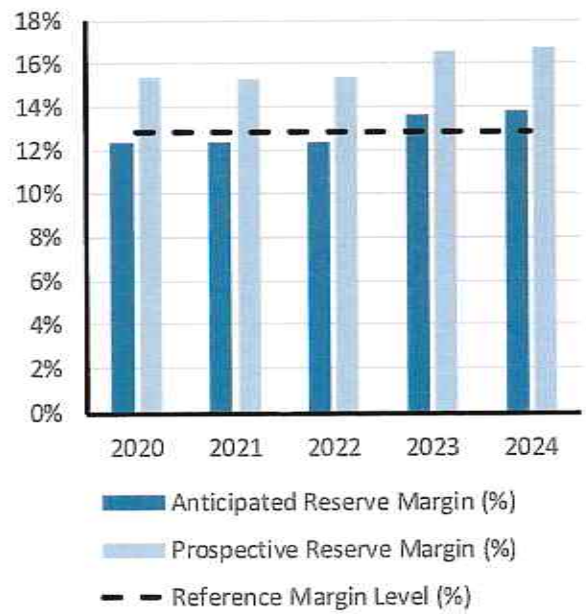
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

Demand, Resources, and Reserve Margins (MW)

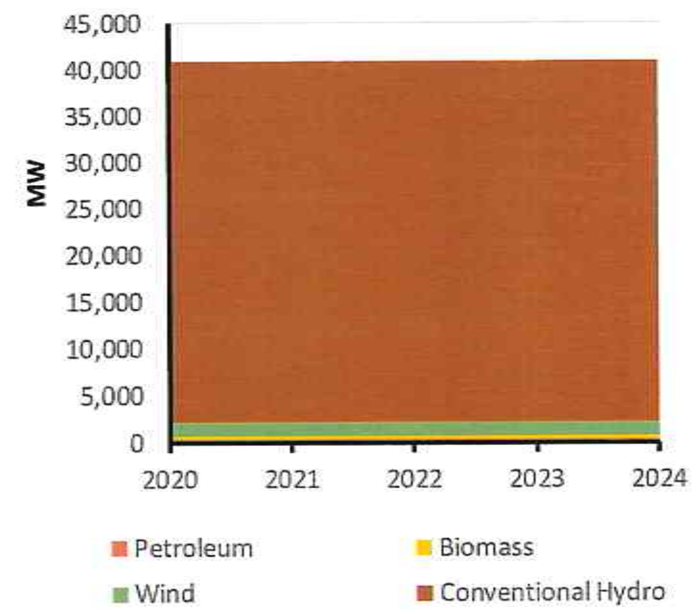
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	39,657	40,359	40,704	40,889	41,130	41,284	41,209	41,432	41,667	41,867
Demand Response	2,748	3,186	3,460	3,807	4,072	3,973	3,720	3,750	3,784	3,792
Net Internal Demand	36,909	37,173	37,244	37,082	37,057	37,311	37,489	37,682	37,884	38,075
Additions: Tier 1	106	351	369	369	391	394	394	394	394	394
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-541	-499	-417	-145	-145	-145	-145	-145	-145	-145
Existing-Certain and Net Firm Transfers	-268	-525	-523	-68	-40	-326	-566	-836	-1,111	-1,375
Anticipated Reserve Margin (%)	12.4%	12.4%	12.4%	13.6%	13.8%	13.0%	12.4%	11.7%	10.9%	10.3%
Prospective Reserve Margin (%)	15.4%	15.3%	15.4%	16.6%	16.7%	16.0%	15.3%	14.6%	13.8%	13.1%
Reference Margin Level (%)	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Bickett-4

Highlights

- The ARM remains above the Reference Margin Level except for winter periods 2020–2021 to 2022–2023 and 2026–2027 to 2029–2030. However, the Prospective Reserve Margin remains above the Reference Margin Level for all seasons and years during the assessment period.
- Approximately 430 MW of capacity additions are expected over the assessment period. The Romaine-4 hydro unit (245 MW) is expected to be fully operational by November 2021.
- A total of 500 MW of firm import capacity from Ontario is available to Quebec each winter through Winter 2022–2023 as part of an existing trade agreement between Québec and Ontario.
- The 250-mile Chamouchouane to Montréal 735 kV Line is now in service.

Québec Fuel Composition										
Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Petroleum	436	436	436	436	436	436	436	436	436	436
Natural Gas	0	0	0	0	0	0	0	0	0	0
Biomass	432	432	432	432	432	432	432	416	407	407
Wind	1,370	1,370	1,370	1,370	1,370	1,372	1,333	1,297	1,257	1,209
Conventional Hydro	38,689	38,689	38,708	38,708	38,730	38,730	38,730	38,730	38,730	38,730
Total MW	40,927	40,927	40,946	40,946	40,968	40,970	40,930	40,878	40,831	40,783

NPCC-Quebec Assessment

Planning Reserve Margins: The ARM is below the Reference Margin Level over the winter periods 2020–2021 to 2022–2023 and 2026–2027 to 2029–2030. However, the Prospective Reserve Margin remains above the Reference Margin Level for all seasons and years during the assessment period. Under the prospective scenario, a total of 1,100 MW of expected capacity imports are planned by the Québec area. These purchases have not yet been backed by firm long-term contracts. However, on an annual basis, the Québec area proceeds with short-term capacity purchases in order to meet its capacity requirements if needed.

Demand: The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. The Quebec area demand forecast average annual growth is 0.8% during the 10-year period, similar to last year's forecast.

Demand-Side Management: The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 1,719 MW on winter 2019–2020 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 280 MW in 2019–20 to 515 MW by 2025–26. Another similar program for residential customers is under development and should gradually rise from 2 MW for Winter 2019–2020 to 621 MW for Winter 2028–2029.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 9 MW for Winter 2019–2020, increasing to 95 MW for Winter 2029–2030. Other dynamic rate options are not considered in the long-term forecast as their impact is not yet certain. These options will be accounted for as DSM resource for the Quebec area once sufficient historical data is available to assess their impact.

Moreover, data centers specialized in blockchain applications, which are part of new developments in the commercial sector, are required to reduce their demand during peak hours at Hydro-Quebec Distribution's request. Their contribution as a resource is expected to peak around 682 MW by Winter 2021–2022 and gradually decline to reach 173 MW at the end of the study period.

Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction.

EE and conservation programs are integrated in the assessment area's demand forecasts.

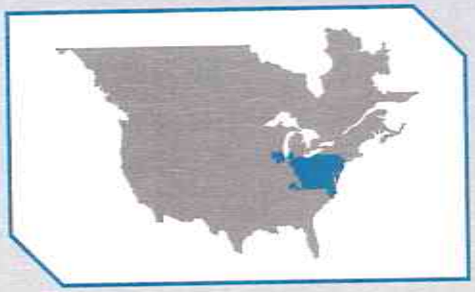
Distributed Energy Resources: Total installed BTM capacity (solar PV) is expected to increase to more than 1,100 MW in 2029. Solar PV is accounted for in the load forecast. Nevertheless, since Quebec is a winter peaking area, DERs on-peak contribution ranges from 1 MW for Winter 2019–2020 to 24 MW for Winter 2029–2030.

Generation: Work is underway on the Romaine-4 unit (245 MW) that is expected to be fully operational in November 2021. The refurbishment of the Rapide-Blanc generating station is expected to start next year. The integration of small hydro units also accounts for 41 MW of new capacity during the assessment period. For other renewable resources, about 371 MW (134 MW on-peak value) of wind capacity has been added to the system in 2018 and 54 MW (20 MW on-peak value) is expected to be in service by 2026. Additionally, 89 MW of new biomass is expected to be in service by 2021.

The capacity contribution of wind resources at peak was revised from 30%–36% for most of the installed capacity, resulting in an increase of peak contribution by approximately 200 MW.

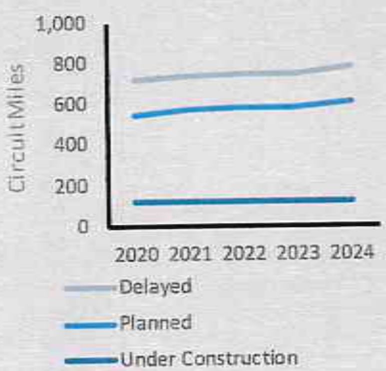
Capacity Transfers: Since 2011, the power transmission system has undergone significant changes, including reduced consumption in the Côte-Nord area and the decommissioning of the Tracy and La Citière thermal and Gentilly-2 nuclear generating station. These changes have brought about an increase to the power flow on the lines of the Manic-Québec corridor toward the major load centers and decreased the reliability of the transmission system. Hydro-Québec is thus required to take steps in order to restore adequate transmission capacity to the corridor and maintain system reliability. After considering a number of scenarios, Hydro-Québec believes that the best solution is to build a new 735 kV line extending some 250 km (155 miles) between Micoua substation in the Côte-Nord area and Saguenay substation in Saguenay–Lac–Saint-Jean. The project also includes adding equipment to both substations and expanding Saguenay substation. Commissioning of the new equipment is planned in 2022.

Transmission: Construction of the Romaine River hydro complex is presently underway. Romaine-4 (245 MW) will be integrated in 2021 at the Montagnais 735/315 kV substation. The Chamouchouane to Montreal 735 kV line is now in service and helps reinforce the transmission system to meet the Reliability Standards. The line (about 400 km or 250 miles) extends from the Chamouchouane substation on the Eastern James Bay subsystem to Duvernay substation near Montréal. This project will reduce transfers on other parallel lines on the southern 735 kV interface, thus optimizing operation flexibility and reducing losses.



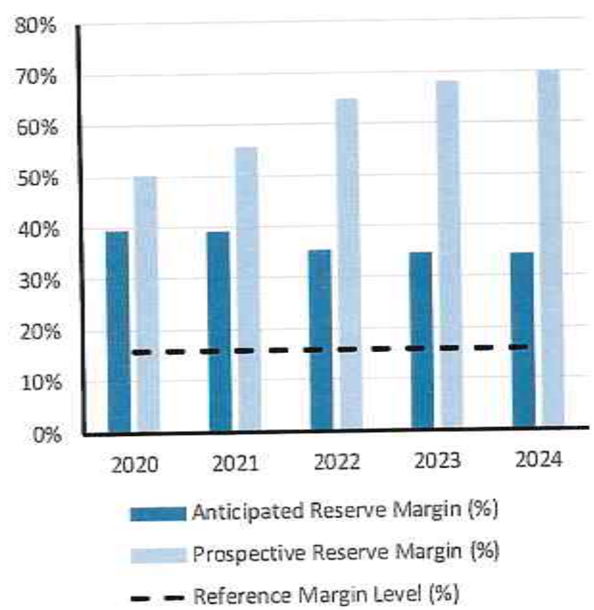
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million people and covers 369,089 square miles. PJM is a BA, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

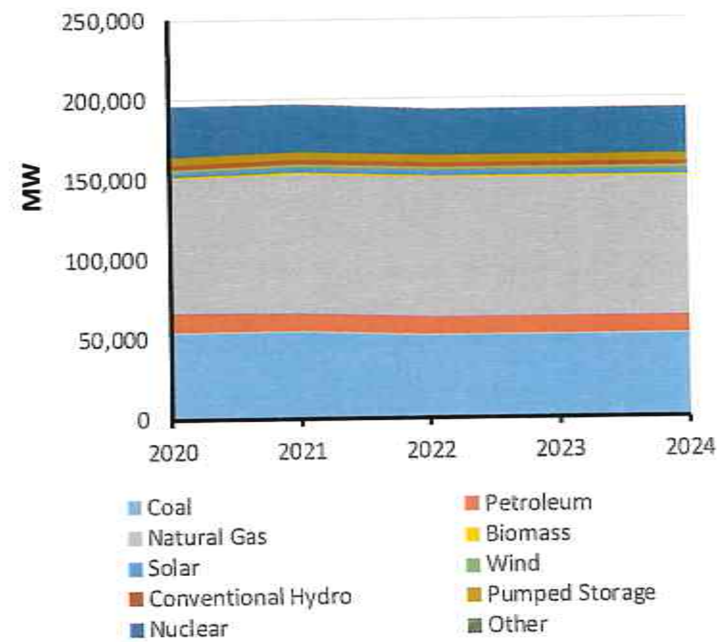


Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)										
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	150,870	151,547	152,253	152,854	153,435	153,988	154,494	155,107	155,891	156,689
Demand Response	9,127	9,118	9,178	9,198	9,243	9,280	9,315	9,343	9,387	9,433
Net Internal Demand	141,743	142,429	143,075	143,656	144,192	144,708	145,179	145,764	146,504	147,256
Additions: Tier 1	13,694	17,907	19,180	19,180	19,180	19,180	19,180	19,180	19,180	19,180
Additions: Tier 2	15,253	23,657	41,021	46,570	50,133	50,379	50,800	50,878	51,042	51,042
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	1,412	1,360	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	183,935	180,439	174,429	174,429	174,429	174,429	174,429	174,429	174,429	174,429
Anticipated Reserve Margin (%)	39.43%	39.26%	35.32%	34.77%	34.27%	33.79%	33.36%	32.82%	32.15%	31.48%
Prospective Reserve Margin (%)	50.19%	55.87%	64.94%	68.14%	69.98%	69.55%	69.29%	68.66%	67.92%	67.06%
Reference Margin Level (%)	15.90%	15.80%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Blackett-4

Highlights

- ARMs do not fall below the Reference Margin Level for any year of the assessment period in PJM. The IRM for the delivery year beginning on June 1, 2019, is 16.0% and decreases to 15.7% for the 2022 delivery year.
- Natural-gas-fired generation capacity now exceeds coal.
- Natural gas plants totaling over 50,468 MW comprise 80% of the generation currently seeking capacity interconnection rights in PJM's new services queue.
- A total of $2.1 billion of baseline transmission investment approved during 2018 continues to reflect a shift in the dynamics driving transmission expansion needed through study year 2025. Flat load growth, EE, generation shifts, and aging infrastructure drivers continue to shift transmission need away from large-scale, cross-system backbone projects towards projects focusing on transmission owner criteria.

PJM Fuel Composition

Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	54,103	54,652	51,884	51,884	51,884	51,884	51,884	51,884	51,884	51,884
Petroleum	12,316	11,294	11,294	11,294	11,294	11,294	11,294	11,294	11,294	11,294
Natural Gas	84,514	87,532	87,559	87,559	87,559	87,559	87,559	87,559	87,559	87,559
Biomass	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166
Solar	2,415	2,655	2,911	2,911	2,911	2,911	2,911	2,911	2,911	2,911
Wind	1,670	1,795	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805
Conventional Hydro	3,133	3,133	3,133	3,133	3,133	3,133	3,133	3,133	3,133	3,133
Pumped Storage	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229
Nuclear	31,653	29,511	28,609	28,609	28,609	28,609	28,609	28,609	28,609	28,609
Other	20	20	20	20	20	20	20	20	20	20
Total MW	196,217	196,987	193,609	193,609	193,609	193,609	193,609	193,609	193,609	193,609

Exhibit Bickett-4

PJM Assessment

Planning Reserve Margins: The ARMs do not fall below the Reference Margin Level for any year of the assessment period in PJM. PJM performs an annual LOLE study to determine the IRM required, satisfying the ReliabilityFirst BAL-502-RFC-02 standard. This standard establishes the "one loss of load event in ten years" LOLE criterion. The IRM for the delivery year beginning on June 1, 2019, is 16.0% and decreases to 15.7% for the 2022 delivery year. The IRM is expressed as a percent above the annual peak demand forecast.

Demand: PJM produces an independent peak load forecast of total internal demand by using econometric regression models with daily load as the dependent variable and independent variables, including calendar effects, weather, economics, and end-use characteristics. The model is estimated with historical data back to 1998, and is used to produce a 15-year forecast for PJM transmission zones, locational deliverability areas and the RTO.

Demand-Side Management: DR resources can participate in all PJM markets: capacity, energy, and ancillary services. PJM requires that PJM member third-party suppliers (curtailment service providers (CSPs)) bring these resources to PJM markets, and it is the responsibility of these CSPs to acts as market operating centers, relaying PJM instructions for load reductions in any of the markets to these resources. CSPs have the ability to participate in PJM's reliability pricing model auctions up to three years in advance of the delivery year (PJM's delivery year is June–May). CSPs registered an overall amount of 9,127 MW for the delivery year 2020–2021 to 9,433 MW in the 2029/2030 delivery year.

Distributed Energy Resources: In early 2015, PJM developed a plan to incorporate distributed solar generation into the long-term load forecast after recognizing the growing market of solar installations. For the purposes of the long-term load forecast, PJM defines distributed solar generation as any solar resource that is not interconnected to the PJM markets. These resources do not go through the full interconnection queue process and do not offer as capacity or as energy resources. Furthermore, the output of these resources is netted directly with the load. PJM does not receive metered production data from any of these resources.

Environmental Information Services, a wholly owned subsidiary of PJM Technologies, Inc., which is a subsidiary of PJM Interconnection, operates the Generation Attribute Tracking System. The generation data that the Generation Attribute Tracking System collects includes distributed solar generation that is behind the meter. Utilizing this collection of data, PJM estimates the amount of distributed solar generation in terms of dc nameplate capacity.

Generation: PJM's regional transmission expansion process (RTEP) continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics, including new generating plants powered by Marcellus and Utica shale natural gas, new wind and solar units driven by federal and state renewable incentives, generating plant deactivations and market impacts introduced by demand resources and EE programs.

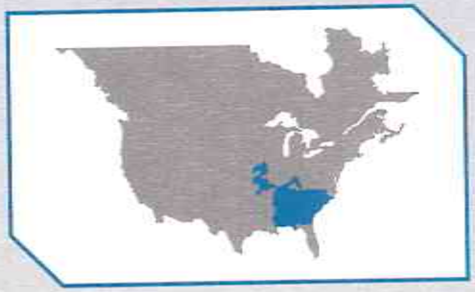
Natural-gas-fired generation capacity now exceeds coal. Natural gas plants that total over 50,468 MW comprise 80% of the generation currently seeking capacity interconnection rights in PJM's new services queue. As for coal, if formally submitted deactivation plans materialize, more than 27,000 MW of coal-fired generation will have deactivated between 2007 and 2021.

Capacity Transfers: PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer into PJM would amount to less than 2% of PJM's internal generation capability. Anticipated capacity does not get anywhere near 2% at any time within this assessment period.

Transmission: The $2.1 billion of baseline transmission investment approved during 2018 continues to reflect a shift in the dynamics driving transmission expansion needed through study year 2025. Flat load growth, EE, generation shifts, and aging infrastructure drivers—among others—continue to shift transmission need away from large-scale, cross-system backbone projects towards projects focusing on transmission owner criteria. PJM Board-approved projects in 2018 will address market efficiency congestion and solve localized reliability criteria violations. Plans reflect lower investment at 345 kV and above over the past four years and higher levels of transmission investment at 230 kV.

In recent years, reviews of existing infrastructure have identified the need for replacement of equipment and structures due to aging. Many 500 kV lines were constructed in the 1960s while 230 kV and 115 kV lines date to the 1950s and earlier. Some TOs have added aging infrastructure to their planning criteria as part of their respective FERC Form No. 715 filings. Planning for aging infrastructure is not new to PJM. Spare 500/230 kV transformers, 500 kV line rebuilds, and a number of other transmission enhancements to mitigate potential equipment failure risk are already an important part of PJM's RTEP. The PJM operating agreement specifies that TO planning criteria are to be evaluated as a part of the RTEP process.

Exhibit Bickett-4



SERC

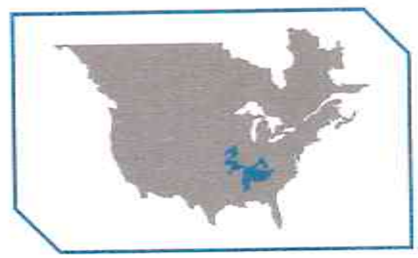
On April 30, 2019, FERC issued an order formally approving the transfer of all registered entities in the Florida Reliability Coordinating Council (FRCC) Region to SERC by July 1, 2019. The integration of FRCC entities resulted in an additional SERC sub-region and SERC assessment area for inclusion in NERC's reliability assessments. SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into four assessment areas: SERC- E, SERC-N, SERC-SE, and SERC-FL Peninsula. The SERC Region includes 36 Balancing Authorities, 21 Planning Authorities, and 4 Reliability Coordinators.

Highlights

- Approximately 21 GW of utility-scale transmission BES-connected solar projects are expected in the interconnection queue over the next five years, developing mostly in SERC-E and FL Peninsula.
- Net capacity resources in the Region are expected to increase for the first five years of the ten-year planning horizon and gradually level out in the last five years with natural-gas-fired capacity additions largely offset by coal-fired capacity retirements.
- SERC is proactively addressing the impacts of increased renewable resources within the SERC footprint and identifying its risks through various forums.
- Across the SERC Region, member companies continue to build transmission, especially in the first five years of the assessment period, to ensure a reliable interconnected power system.

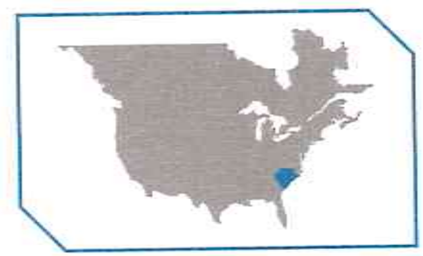
Starting on the next page are summaries of the assessment areas that make up SERC.

SERC-SE



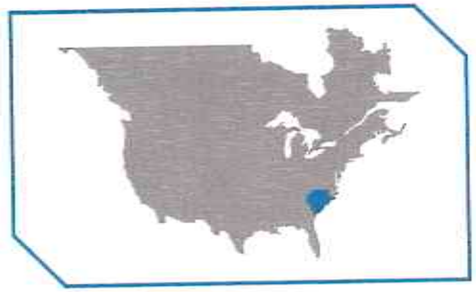
SERC-C

SERC-FP



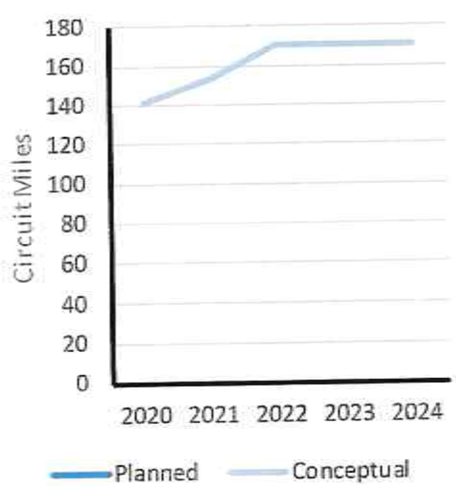
SERC-E

Exhibit Bickett-4

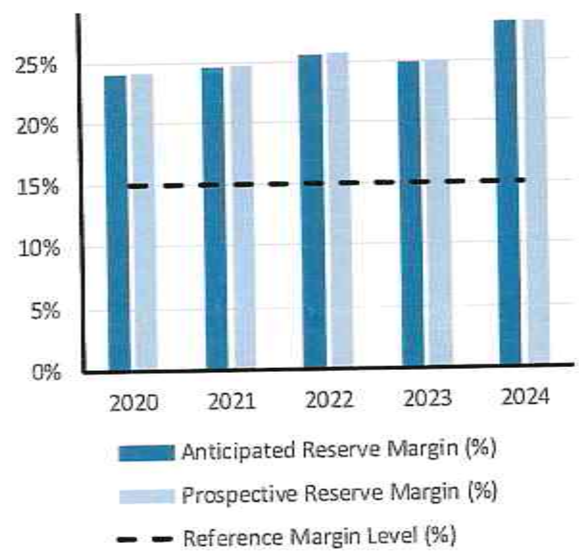


SERC-E

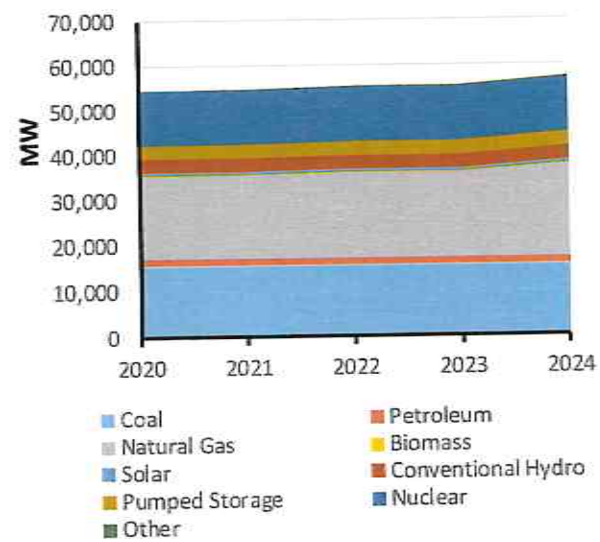
Demand, Resources, and Reserve Margins (MW)										
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	45,119	45,327	45,461	45,811	46,056	46,402	46,791	47,210	47,674	48,052
Demand Response	966	970	973	976	973	974	975	976	977	978
Net Internal Demand	44,153	44,357	44,488	44,835	45,083	45,428	45,816	46,234	46,697	47,074
Additions: Tier 1	624	702	1,249	1,285	3,061	3,097	4,435	5,773	7,613	7,613
Net Firm Capacity Transfers	191	530	530	530	530	530	530	530	530	530
Existing-Certain and Net Firm Transfers	54,153	54,561	54,632	54,697	54,703	54,703	54,703	54,471	53,345	53,345
Anticipated Reserve Margin (%)	24.06%	24.59%	25.61%	24.86%	28.13%	27.23%	29.08%	30.30%	30.54%	29.49%
Prospective Reserve Margin (%)	24.16%	24.68%	25.70%	24.96%	28.22%	27.33%	29.17%	30.39%	30.63%	29.58%
Reference Margin Level (%)	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%



Projected Transmission Circuit Miles



Planning Reserve Margins



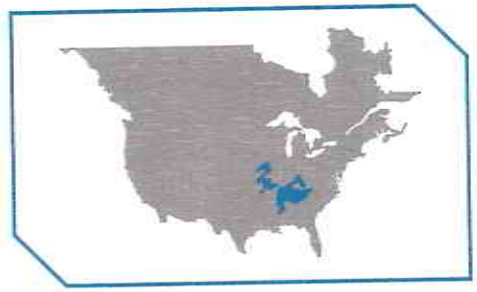
Existing and Tier 1 Resources

Exhibit Bickett-4

SERC-E Fuel Composition

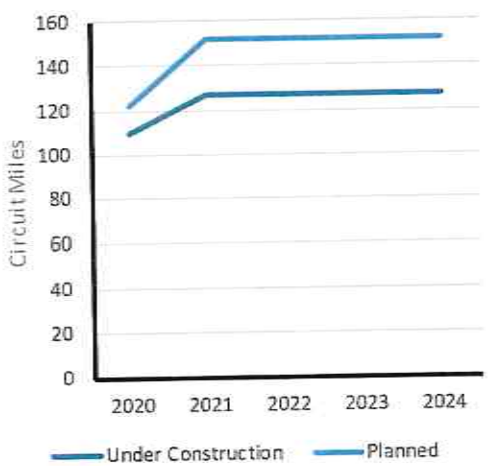
Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	15,552	15,552	15,552	15,552	15,552	15,552	15,552	15,552	14,422	14,422
Petroleum	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,464	1,464	1,464
Natural Gas	18,479	18,523	19,036	19,036	20,776	20,776	22,114	23,288	25,128	25,128
Biomass	164	164	164	164	164	164	164	164	164	164
Solar	447	447	447	447	447	447	447	447	447	447
Conventional Hydro	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145
Pumped Storage	3,109	3,174	3,239	3,304	3,304	3,304	3,304	3,304	3,304	3,304
Nuclear	12,115	12,119	12,125	12,125	12,131	12,131	12,131	12,131	12,135	12,135
Other	44	78	112	148	184	220	220	220	220	220
Total MW	54,586	54,733	55,351	55,452	57,234	57,270	58,608	59,714	60,428	60,428

Exhibit Bickett-4

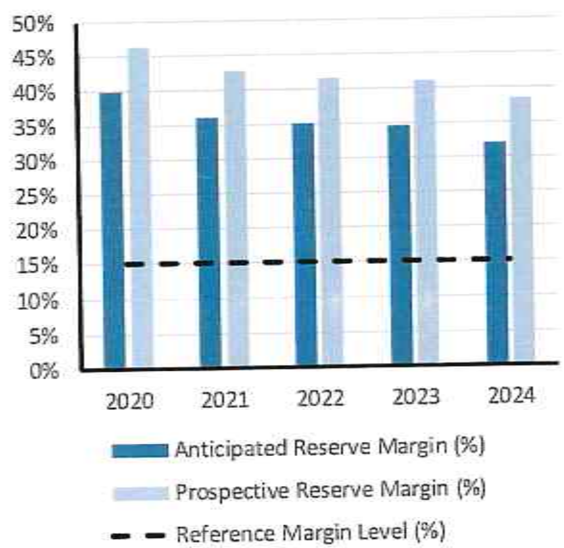


SERC-C

Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Demand, Resources, and Reserve Margins (MW)										
Total Internal Demand	41,076	41,327	41,593	41,724	41,868	41,861	42,008	42,221	42,410	42,576
Demand Response	1,967	1,896	1,847	1,817	1,815	1,815	1,815	1,815	1,815	1,815
Net Internal Demand	39,109	39,431	39,746	39,907	40,053	40,046	40,193	40,406	40,595	40,761
Additions: Tier 3	0	0	0	0	1,012	1,012	1,013	1,014	2,028	2,029
Net Firm Capacity Transfers	432	432	361	361	361	361	361	186	186	186
Existing-Certain and Net Firm Transfers	54,666	53,692	53,696	53,757	52,889	52,940	52,940	52,765	52,765	52,765
Anticipated Reserve Margin (%)	39.78%	36.17%	35.10%	34.71%	32.05%	32.20%	31.71%	30.59%	28.58%	27.35%
Prospective Reserve Margin (%)	46.31%	42.64%	41.52%	41.09%	38.41%	38.56%	38.06%	36.90%	34.83%	33.56%
Reference Margin Level (%)	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%



Projected Transmission Circuit Miles



Planning Reserve Margins

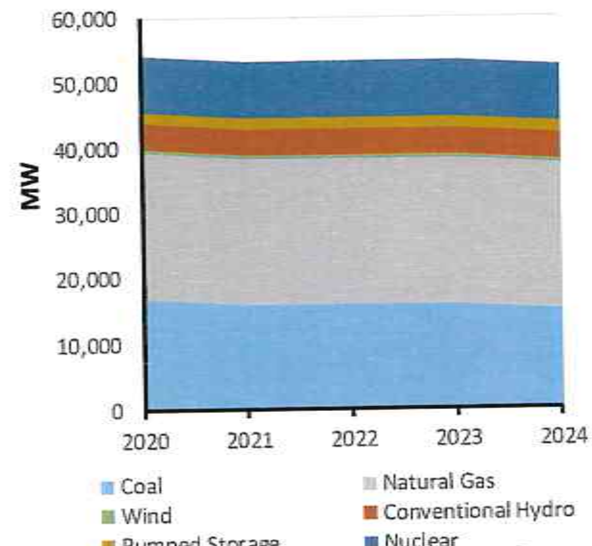
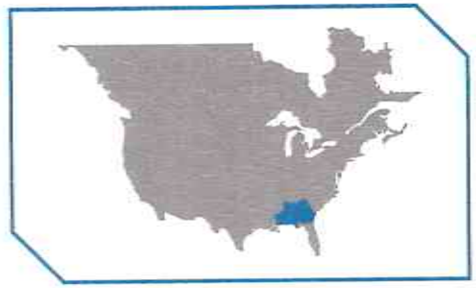


Exhibit Bickett-4

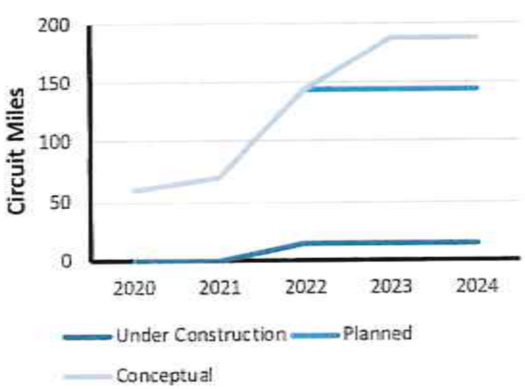
Existing and Tier 1 Resources

SERC-C Fuel Composition										
Generation Type	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Coal	17,068	16,083	16,083	16,083	15,215	15,215	15,215	15,215	15,215	15,215
Natural Gas	22,408	22,408	22,408	22,408	22,408	22,408	22,408	22,408	22,408	22,408
Wind	334	334	334	334	334	334	334	334	334	334
Conventional Hydro	4,058	4,058	4,079	4,140	4,140	4,191	4,191	4,191	4,191	4,191
Pumped Storage	1,758	1,769	1,823	1,823	1,823	1,823	1,823	1,823	1,823	1,823
Nuclear	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609	8,609
Total MW	54,234	53,260	53,334	53,396	52,528	52,579	52,579	52,579	52,579	52,579

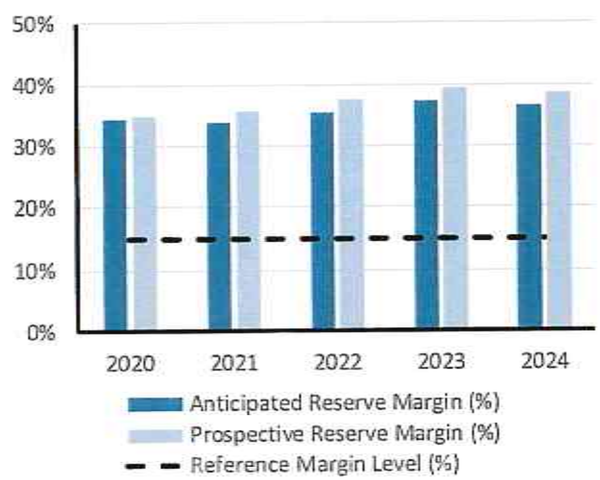


SERC-SE

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	47,655	48,040	48,169	48,246	48,514	48,750	48,302	47,401	47,536	48,011
Demand Response	2,466	2,638	2,638	2,638	2,605	2,598	2,591	2,591	2,592	2,593
Net Internal Demand	45,189	45,402	45,531	45,608	45,909	46,152	45,711	44,810	44,944	45,418
Additions: Tier 1	903	1,010	2,110	3,210	3,210	3,210	3,210	3,210	3,210	3,210
Additions: Tier 2	0	630	705	705	705	705	705	705	705	705
Additions: Tier 3	1,228	1,953	2,188	2,188	2,188	2,188	2,188	2,188	2,188	2,188
Net Firm Capacity Transfers	-1,888	-1,930	-2,120	-2,306	-2,237	-2,216	-2,211	-2,209	-2,207	-2,204
Existing-Certain and Net Firm Transfers	59,801	59,768	59,578	59,392	59,461	59,470	59,475	59,477	59,479	59,482
Anticipated Reserve Margin (%)	34.33%	33.87%	35.49%	37.26%	36.51%	35.81%	37.13%	39.90%	39.48%	38.03%
Prospective Reserve Margin (%)	34.97%	35.89%	37.67%	39.44%	38.68%	37.96%	39.31%	42.11%	41.69%	40.22%
Reference Margin Level (%)	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%



Projected Transmission Circuit Miles



Planning Reserve Margins

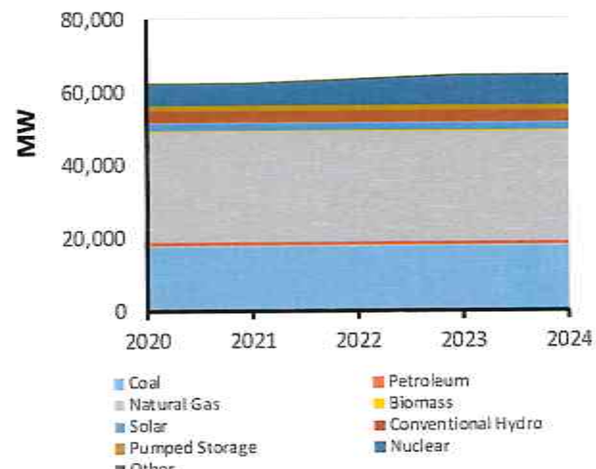
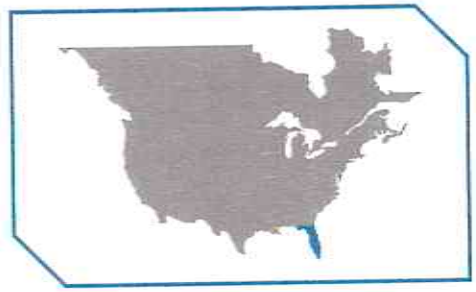


Exhibit Bickett-4

Existing and Tier 1 Resources

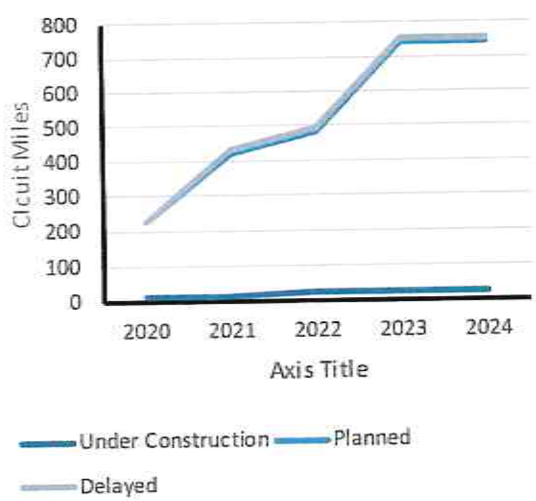
SERC-SE Fuel Composition										
Generation Type	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Coal	17,910	17,910	17,910	17,910	17,910	17,910	17,910	17,910	17,910	17,910
Petroleum	961	961	961	961	961	961	961	961	961	961
Natural Gas	30,294	30,304	30,304	30,304	30,304	30,292	30,292	30,292	30,292	30,292
Biomass	341	341	341	341	341	341	341	341	341	341
Solar	2,032	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139
Conventional Hydro	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288
Pumped Storage	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632
Nuclear	5,818	5,818	6,918	8,018	8,018	8,018	8,018	8,018	8,018	8,018
Other	315	315	315	315	315	315	315	315	315	315
Total MW	62,592	62,708	63,808	64,908	64,908	64,896	64,896	64,896	64,896	64,896

Exhibit Bickett-4

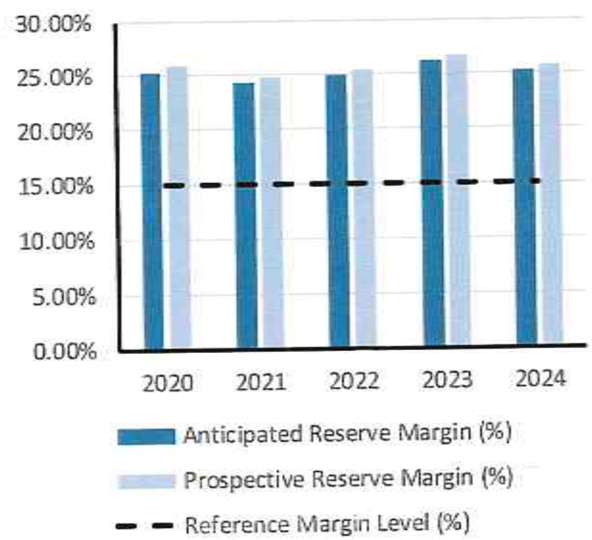


SERC-FP

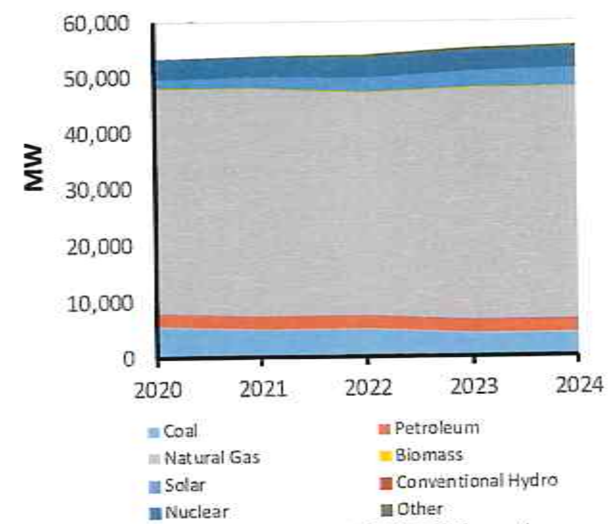
Demand, Resources, and Reserve Margins (MW)										
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	48,153	48,675	49,161	49,663	50,315	50,924	51,600	52,333	53,033	53,033
Demand Response	3,104	3,153	3,204	3,253	3,300	3,348	3,395	3,440	3,488	3,488
Net Internal Demand	45,049	45,522	45,957	46,410	47,015	47,576	48,205	48,893	49,545	49,545
Additions: Tier 1	2,935	3,955	6,781	8,855	9,551	10,033	12,224	13,040	13,393	13,427
Net Firm Capacity Transfers	1,356	1,082	1,107	1,132	1,132	1,132	1,032	1,032	1,032	1,032
Existing-Certain and Net Firm Transfers	53,514	52,634	50,635	49,707	49,343	49,303	48,892	47,869	47,705	47,705
Anticipated Reserve Margin (%)	25.30%	24.31%	24.93%	26.18%	25.27%	24.72%	26.78%	24.58%	23.32%	23.39%
Prospective Reserve Margin (%)	25.87%	24.87%	25.49%	26.73%	25.81%	25.25%	27.31%	25.10%	23.83%	23.90%
Reference Margin Level (%)	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Bickett-4

SERC-FP Fuel Composition										
Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	5,681	5,036	5,036	4,159	4,159	4,159	4,159	4,159	4,159	4,159
Petroleum	2,357	2,357	2,357	2,357	2,357	2,357	2,186	1,855	1,855	1,855
Natural Gas	39,903	40,584	39,685	41,342	41,463	41,463	43,474	43,439	43,277	43,277
Biomass	103	103	103	103	103	103	103	103	103	103
Solar	1,553	1,912	2,558	2,898	3,264	3,745	3,819	4,154	4,463	4,455
Conventional Hydro	44	44	44	44	44	44	44	44	44	44
Nuclear	3,637	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657
Other	15	15	484	484	484	484	484	484	484	484
Total MW	53,291	53,706	53,921	55,042	55,530	56,010	57,925	57,894	58,041	58,033

SERC Assessment

Planning Reserve Margins: ARMs range between 18%–31% across all assessment areas and do not fall below the 15% NERC Reference Margin Level. Additionally, all assessment areas maintain ten-year **reserve margins above SERC's internally calculated Reference Reserve Margin, using the metric of 0.1 days per year LOLE, of 14.4%.**

Demand: Projected demand growth within the assessment areas have decreased to less than 1% over the years, with the exception of FL Peninsula with a growth rate of slightly above 1% (1.15%). Although some metro areas are experiencing higher growth rates compared to rural areas, entities report load reductions due to BTM distributed generation and appliance standards. These factors will continue suppressing the load in the future.

Demand Side Management: DR programs are minimal and vary among the assessment areas (e.g., summer load control, reserve preservation, voltage optimization, five minute, 60 minute, or instantaneous response). These programs are used to control peak demand. Throughout the year, entities monitor and evaluate each program's operational functionality to determine effectiveness and ability to provide demand reduction.

Distributed Energy Resources: Most of the DER growth in the Region has been solar. The queued amount of DERs connected to the non-BES, subtransmission system (e.g., roof-top solar, plug-in electric vehicles) is approximately 2,100 MW. To date, there are no notable reliability impacts reported to the Region. However, the Region is working within its data collection processes to collect the appropriate level of data (i.e., MWs in the queue) so that these resources can be modeled and analyzed for potential impact to the system.

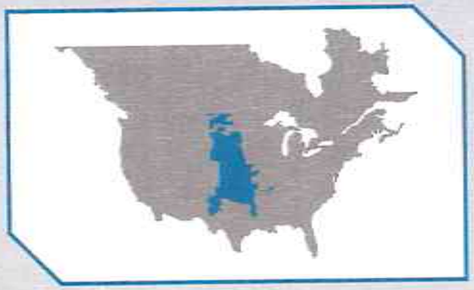
Generation: SERC entities have sufficient generation to meet demand over the period. New resources are expected, which include a combination of capacity purchases, new nuclear, natural gas, and combined-cycle units. Natural gas (47.4%), coal (26.5%), and nuclear (13.1%) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types (8%) are minimal. Entities within SERC will add approximately 3,700 MW of natural gas generation over the period. SERC-E will have an additional 2,200 MW of nuclear additions available to meet demand in 2021. Overall, the assessment areas will encounter 6,100 MW of net additions and retirements over within the next 10 years. Approximately 21 GW of utility-scale transmission BES-connected solar projects are expected in the interconnection queue over the next five years and are largely developing in SERC-E and FL-Peninsula. No reliability issues are expected within the assessment areas, but entities are continuing to monitor the impacts of solar generators as they are added to the interconnection queue. Entities are studying winter season impact of additional solar to the resource mix and load forecast. As more BTM solar generation is added, some entities anticipate becoming winter-peaking systems, providing additional motivation to enforce winter reserve margins.

Transmission: Across the SERC Region, entities continue to build transmission, especially in the first five years of the assessment period, to ensure a reliable interconnected power system. SERC entities are expecting a total of 862 miles (i.e., 450 miles of >100 kV, 340 miles of >200 kV, 12 miles of >300 kV, and 60 miles of >60kV) of transmission additions over the period. These projects are in the design/construction phase and are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers (i.e., 345/138kV and 161/500kV), reconductoring existing transmission lines, and other system reconfigurations/additions to support transmission system reliability. Entities in SERC-N are currently constructing a 500 kV sub- station to alleviate decreasing voltages and higher flows on lines caused by increased loads in the area. In addition, SERC-N is planning a 500 kV substation that will support system reliability for a confirmed resource retirement. In addition, a new Static VAR Compensator is being planned for an existing 500 kV substation to support the stability of local generating units.

Entities coordinate transmission expansion plans during the Region's annual joint model building and study efforts. These plans are also coordinated with entities external to the Region through annual joint modeling efforts within the Eastern Interconnection Reliability Assessment Group and the Multi-regional Modeling Working Group. In addition to these forums, several entities participate in open regional transmission planning processes driven by FERC Order 890. Transmission expansion plans by most SERC entities are dependent on regulatory support at the federal, state, and local levels since the regulatory entities can influence the siting, permitting, and cost recovery of new transmission facilities.

Entities do not anticipate any transmission limitations or constraints that cause significant impacts to reliability. However, limitations exist near generation sites in SERC-N and along the seams due to line loading and transfers on the transmission system. Constraints will be mitigated by future transmission projects (e.g., new builds, reactor), generation adjustments, system reconfiguration, and/or system power purchases.

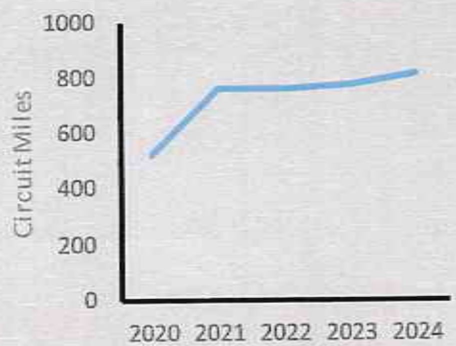
Exhibit Bickett-4



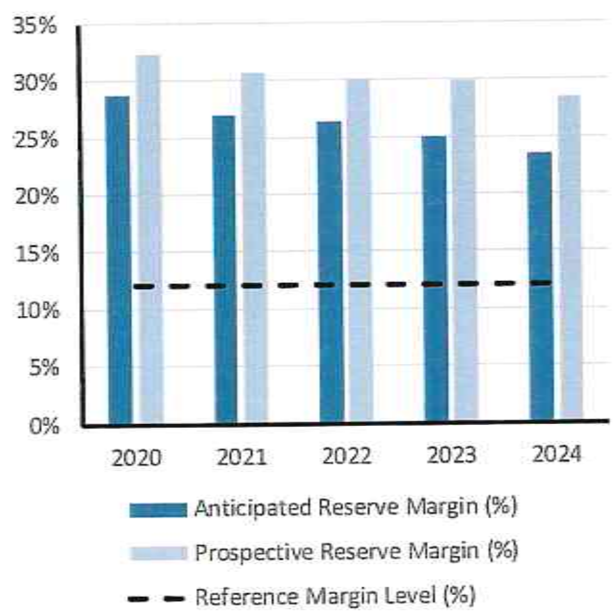
SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint that touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations and serves a population of more than 18 million people.

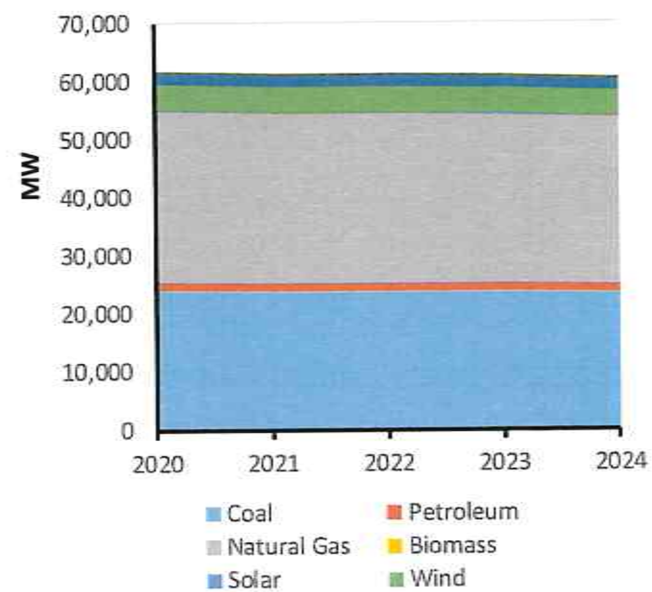
Demand, Resources, and Reserve Margins (MW)										
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	53,478	54,161	54,535	54,885	55,178	55,428	55,648	55,903	56,179	56,465
Demand Response	1,078	1,060	1,124	1,149	1,167	1,212	1,259	1,302	1,330	1,258
Net Internal Demand	52,401	53,102	53,411	53,736	54,011	54,216	54,389	54,602	54,849	55,206
Additions: Tier 1	0	300	300	300	300	300	300	300	300	300
Additions: Tier 2	2,500	2,500	2,500	3,150	3,150	3,150	3,150	3,150	3,150	3,150
Additions: Tier 3	2,354	33,311	49,344	54,431	63,940	64,013	64,013	64,013	64,013	64,013
Net Firm Capacity Transfers	-303	-243	-141	-141	-96	-76	-76	-126	-126	-126
Existing-Certain and Net Firm Transfers	67,453	67,158	67,232	66,921	66,458	66,222	65,845	65,040	64,793	64,690
Anticipated Reserve Margin (%)	28.73%	27.04%	26.44%	25.10%	23.60%	22.70%	21.62%	19.67%	18.68%	17.72%
Prospective Reserve Margin (%)	32.45%	30.71%	30.09%	29.94%	28.42%	27.50%	26.40%	24.43%	23.42%	22.44%
Reference Margin Level (%)	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Brickett-4

Highlights

- SPP projects to maintain more than enough capacity to meeting the planning reserve requirement during the assessment time frame.
- SPP continues to see significant increase in wind penetration and set new wind penetration levels and peaks in 2019.

SPP Fuel Composition

Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	23,985	23,765	23,766	23,765	23,492	23,492	23,493	23,024	22,840	22,840
Petroleum	1,446	1,446	1,446	1,446	1,446	1,446	1,376	1,376	1,325	1,325
Natural Gas	29,583	29,331	29,330	29,045	28,795	28,515	28,159	27,888	27,888	27,776
Biomass	25	25	25	25	25	25	25	25	25	25
Solar	179	179	179	179	179	179	179	179	179	179
Wind	4,359	4,359	4,359	4,359	4,359	4,359	4,359	4,359	4,359	4,359
Nuclear	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
Other	284	284	284	284	284	284	284	284	284	284
Total MW	61,805	61,333	61,334	61,048	60,525	60,245	59,820	59,080	58,845	58,733

Exhibit Bickett-4

SPP Assessment

Planning Reserve Margins: The ARM does not fall below the Reference Margin Level of 12% for the entire ten-year assessment period. The Reference Margin Level is determined by a probabilistic LOLE study.

Demand: SPP load peaks during the summer season; the 2019 load forecast is projected to peak at 53,218 MW, a projected increase compared to the previous year's LTRA forecast for the 2019 summer season. SPP forecasts the non-coincident annual peak growth based on member submitted data over the 10-year assessment time frame. The current annual growth rate is approximately .06%.

Demand-Side Management: SPP's EE and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area.

Distributed Energy Resources: SPP currently has approximately 250 MW of installed solar generating facilities. SPP Model Development, Economic Studies, and the Supply Adequacy working groups are currently developing policies and procedures around DERs. These policies will become effective during 2020 and will affect the SPP resource adequacy process. SPP resources adequacy staff are working to create a process that notifies SPP operations and the RC of new resources that are available outside of the SPP integrated marketplace mechanisms.

Generation: Since the *2018 LTRA*, more 1,000 MW of nameplate capacity has been retired in SPP. The generation that has been retired over the past year has mainly been replaced with wind resources. The impact to the resource adequacy in the SPP is being assessed in the 2019 LOLE study. Currently, SPP is not expecting any long-term reliability impacts resulting from generating plant retirements.

Capacity Transfers: The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinates the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

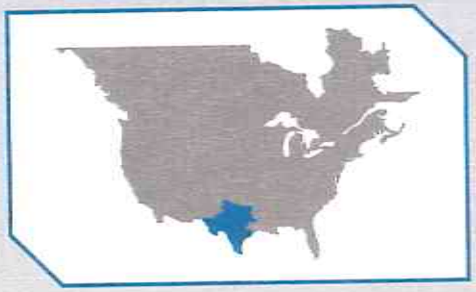
In April 2019, SPP and ERCOT executed a coordination plan that superseded the prior coordination agreement. The coordination plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers, and switchable generation resources (SWGRs). Under the terms of the coordination plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfy the resource adequacy requirements contained in Attachment AA of the SPP *Open Access Transmission Tariff*.[37]

Transmission: The SPP Board of Directors approved the *2018 Integrated Transmission Plan Near-Term Assessment* and the *2019 SPP Transmission Expansion Plan Report*.[38] Both reports provide details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users.

37 SPP OATT: https://www.spp.org/spp-documents-filings/?id=18340

38 https://www.spp.org/documents/56611/2019%20spp%20transmission%20expansion%20plan%20report.pdf

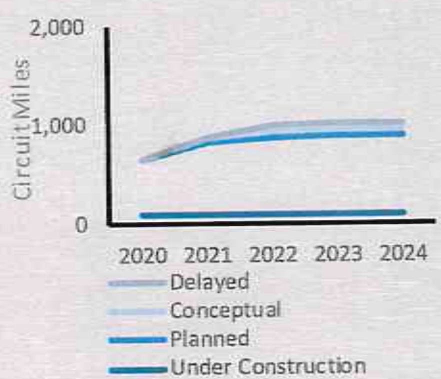
Exhibit Bickett-4



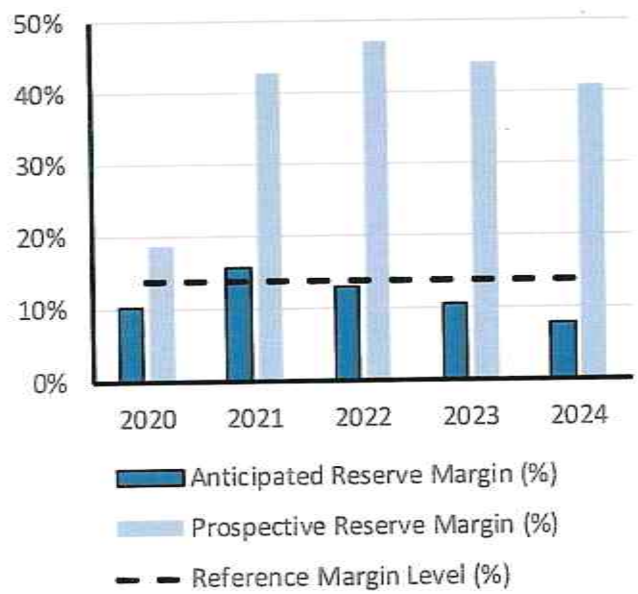
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the PUC of Texas and the Texas legislature. ERCOT is a summer-peaking area that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 650 generation units, and serves 25 million customers. The Texas Reliability Entity (Texas RE) is responsible for the RE functions described in the *Energy Policy Act of 2005* for the ERCOT Region.

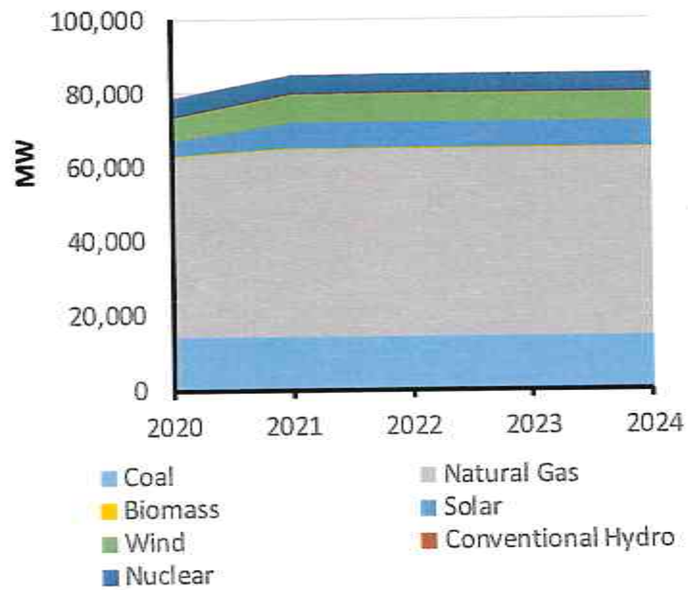
Demand, Resources, and Reserve Margins (MW)										
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	76,845	78,824	80,590	82,506	84,121	85,732	87,345	88,913	90,426	91,914
Demand Response	2,251	2,231	2,231	2,231	2,231	2,231	2,231	2,231	2,231	2,231
Net Internal Demand	74,594	76,593	78,359	80,276	81,891	83,501	85,115	86,682	88,195	89,684
Additions: Tier 1	4,628	10,546	10,778	10,778	10,778	10,778	10,778	10,778	10,778	10,778
Additions: Tier 2	5,467	21,115	27,232	27,972	27,972	27,972	27,972	27,972	27,972	27,972
Additions: Tier 3	912	12,509	22,017	23,031	23,031	23,031	23,031	23,031	23,031	23,031
Net Firm Capacity Transfers	50	50	50	50	50	50	50	50	50	50
Existing-Certain and Net Firm Transfers	77,602	77,907	77,769	77,769	77,514	77,514	77,514	77,514	77,514	77,514
Anticipated Reserve Margin (%)	10.24%	15.48%	13.00%	10.30%	7.82%	5.74%	3.73%	1.86%	0.11%	-1.55%
Prospective Reserve Margin (%)	18.68%	42.88%	47.20%	44.15%	41.00%	38.28%	35.66%	33.20%	30.92%	28.74%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Exhibit Bickett-4

Highlights

- Relative to the *2018 LTRA*, ERCOT's ARMs are lower through 2020 but higher for 2021 through 2023. The near-term decrease is mainly due to a change in the reporting of capacity transfers across two dc ties connected to the SPP system and the cancellation or delay of planned generation projects.
- To incentivize more investment in plant maintenance and new generation capacity, the PUC of Texas directed ERCOT to make changes to the real-time operating reserve price adder methodology. These changes allow resource owners to earn greater operating reserve revenues as reserve capacity becomes scarce.
- Peak demand forecasts increased since last year, reflecting robust growth in oil and natural gas exploration activity in West Texas.
- ERCOT continues to see strong interest in solar and wind project development. There is currently 8,229 nameplate MW wind resources and 3,479 MW solar resources expected to be in service by the 2020 summer season based on developer reporting.
- ERCOT's latest list of transmission projects includes the addition or upgrade of 2,347 miles of 138 kV, 345 kV transmission circuits, and 17,033 MVA of 345/138 kV autotransformer capacity projects that are planned to be in service between 2019 and 2024.

Note: Generation interconnection queues in the ERCOT area are continually changing and the pace of queue entry has increased since tight conditions in late Summer 2019. Data used in ERCOT ISO's December 5, 2019, *Capacity, Demand and Reserves Report*[39] shows a higher future peak reserve range of 18%–13% versus 15%–8% in the LTRA for the years 2021 to 2024. Primary differences between this *2019 LTRA* and the *Capacity, Demand, and Reserves Report* reflect a downward revision to the ERCOT load forecast of approximately 1%–1.5% with a marked increase in utility-scale solar expected in Summer 2021.

Texas RE-ERCOT Fuel Composition

Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	14,225	14,225	14,225	14,225	14,225	14,225	14,225	14,225	14,225	14,225
Natural Gas	48,531	50,634	50,634	50,634	50,634	50,634	50,634	50,634	50,634	50,634
Biomass	186	186	186	186	186	186	186	186	186	186
Solar	3,949	6,885	7,072	7,072	7,072	7,072	7,072	7,072	7,072	7,072
Wind	6,272	7,536	7,581	7,581	7,581	7,581	7,581	7,581	7,581	7,581
Conventional Hydro	462	462	462	462	462	462	462	462	462	462
Nuclear	4,960	4,960	4,960	4,960	4,960	4,960	4,960	4,960	4,960	4,960
Total MW	78,585	84,887	85,119	85,119	85,119	85,119	85,119	85,119	85,119	85,119

39 http://www.ercot.com/content/wcm/lists/167023/CapacityDemandandReserveReport-Dec2019.pdf

TRE-ERCOT Assessment

Planning Reserve Margins: The summer ARM falls below the Reference Margin Level of 13.75% for four of the first five summers of the assessment period and remains below it for the duration of the LTRA forecast period. Relative to the *2018 LTRA*, the ARMs are lower through 2020 but higher for 2021 through 2023. The near-term drop in the reserve margin is mainly due to the cancellation or delay of planned generation projects, a relative increase in the forecasted summer peak demands, a change in the reporting of capacity transfers across two dc ties connected to the SPP system (described in more detail below), summer capacity rating decreases for a number of operational natural-gas-fired units, and the mothballing of a coal-fired plant.

Response to Lower Reserve Margins: In response to lower summer reserve margins and higher energy prices, ERCOT expects high availability of existing resources during 2020 summer peak demand periods. To incentivize more investment in plant maintenance and new generation capacity, the PUC of Texas directed ERCOT in January 2019 to make a two-phased change to the real-time operating reserve price adder methodology with the first phase already implemented for Summer 2019. These changes allow resource owners to earn greater operating reserve revenues as reserve capacity becomes scarce. ERCOT also expects market responses in the form of temporary reductions in demand; for example, there are programs operated by ERCOT, retail electric providers, and distribution utilities that compensate customers for reducing their demand or operating their own generation in response to market prices and anticipated capacity scarcity conditions. In order to maintain system reliability, ERCOT has a series of emergency procedures that may be used when operating reserves drop below specified levels; examples include releasing load resource capacity qualified to provide responsive reserve ancillary service, requesting available emergency power across the direct current ties to neighboring grids, and requesting emergency support from available switchable generators currently serving non-ERCOT grids.

Demand: According to ERCOT's latest long-term peak demand forecast that was prepared in the fall of 2018, annual peak demand is expected to increase by a compounded annual rate of 2.1% from 2019 through 2029. To compare this with the historical trend, the growth rate from 2002 through 2018 was 1.7%. This forecast is also higher than the forecast used for the *2018 LTRA* mainly due to greater oil and natural gas exploration activity in the Permian Basin area of West Texas. ERCOT's long-term load forecast is based on a set of models describing the hourly load in eight weather zones as a function of the number of premises in various customer classes (e.g., residential, business, industrial), economic variables, weather variables (e.g., heating and cooling degree days, temperature, cloud cover, wind speed, dew point), and calendar variables (e.g., day of week, holiday).

Demand-Side Management: The DSM forecasted for 2019 comes from dispatchable resources in the form of non-controllable load resources providing responsive reserve service (1,173 MW), emergency response service (809 MW, based on actual contracted capacity), and load management programs administered by transmission/distribution service providers (291 MW, based on initial projections provided by the TDSPs). These forecasts show a gross-up of 2–reflect avoided transmission line losses. For 2019 and beyond, ERCOT assumes that the load resource capacity amounts remain constant. The ERS capacity forecast declines to 788 MW for 2020 and then to 768 MW for 2021 and thereafter. These figures are based on a three-year historical compounded program growth rate along with the 2% gross-up. ERCOT develops its own EE forecast using annual reports of verified incremental peak load EE impacts from the Public Utility Commission of Texas and Texas State Energy Conservation Office.

Distributed Energy Resources: Installed solar DER capacity forecasted for the five-year horizon (ending 2024) is approximately 2,580 MW. This forecast is higher than the one used for the *2018 LTRA* and reflects the use of an S-curve adoption model that replaces a flat annual growth rate approach used last year. ERCOT continues to advance several initiatives in 2019 intended to address DERs in operations and planning; a protocol revision request to establish location marginal price settlement rules was submitted in January. A protocol revision request to map existing registered DERs (>1 MW and importing into the grid) to the Common Information Model at their load points was approved in April. New requirements for reporting unregistered DERs below 50 kW in size were approved in May. ERCOT is also working on DER forecasting processes for day-ahead and real-time operations.

Generation: Since Summer 2018, 2,447 MW of utility-scale installed capacity has been approved for commercial operations in ERCOT. The percentage contributions by fuel type are wind at 47%, natural gas at 28%, and solar at 25%. In addition, 125 MW of incremental capacity due to upgrades at existing thermal units was also commercially approved during 2019. The 470 MW Gibbons Creek coal-fired unit was indefinitely mothballed, and the unit's owner has subsequently notified ERCOT that it plans to retire the unit effective October 2019. ERCOT continues to see strong interest in solar and wind project development; there is currently 8,229 nameplate MW of Tier 1 wind resources and 3,479 MW of Tier 1 solar resources that are expected to be in service by the 2020 summer season based on developer reporting. ERCOT continues to implement enhancements to tools and processes to address increasing amounts of renewable generation on the ERCOT grid. ERCOT added intra-hour wind forecasting to its operations and is including five-minute wind ramp forecasts in its calculation of generation to be dispatched as part of security-constrained economic dispatch. This

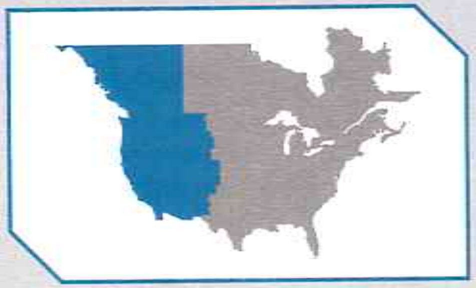
Exhibit Bickett-4

change is intended to take the burden off of regulation service to cover the five-minute gain or loss of generation from variations in wind and instead dispatch this energy economically. This change will also aid in reducing frequency recovery duration following events that occur during times with significant wind up and down ramps.

To estimate the amount of renewable capacity available to meet seasonal peak loads, ERCOT relies on average historical telemetered high sustained limits during the 20 highest peak load hours for each season over a span of years specific to the renewable generation type. For wind, the historical period for averaging is 10 years for non-coastal resources (2009–2018) and nine years for coastal resources (2010–2018). For solar and hydro, the historical period is three years (2016–2018).

Capacity Transfers: For the *2019 LTRA*, ERCOT is reporting 770 MW of ERCOT-SPP transfer capability across two dc ties (out of a total of 820 MW) as expected imports from SPP and 50 MW as firm imports. This accounting approach recognizes SPP's new resource adequacy requirement process implemented in 2019. Included in the expected imports amount is a forecast of 63 MW contributed by the three dc ties connected to the Mexican grid. Since ERCOT-SPP dc tie capacity has been handled as firm imports to ERCOT in past LTRAs, this change significantly impacts the calculation of Anticipated and Prospective Reserve Margins. Based on applying ERCOT's own transmission and resource adequacy assessment assumptions, anticipated resources for Summer 2019 would increase by 728 MW, resulting in an ARM of 8.6%. ERCOT's dc tie planning assumptions reflect a high probability that the ERCOT-SPP ties will continue to be used for importing energy at near their full rated capacities during peak load hours.

Transmission: ERCOT's latest list of transmission projects includes the addition or upgrading of 2,347 miles of 138 kV and 345 kV transmission circuits and 17,033 MVA of 345/138 kV autotransformer capacity projects that are planned to be in service between 2019 and 2024. Due to continued strong load growth in West Texas, ERCOT recommended several large new transmission projects, including a new 345 kV loop between the Moss switch station and the Bakersfield station with six new 600 MVA 345/138 kV autotransformers: two at Riverton switch station, two at Sand Lake substation, and two at Solstice switch station. A related project will add two 250 MVAR STATCOMs in the area. The projects are expected to be in place prior to the 2021 summer peak.



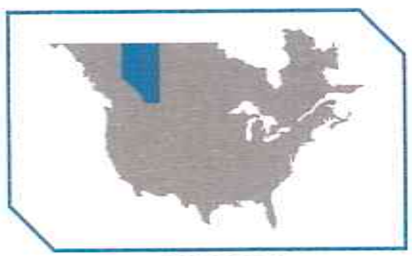
WECC

WECC is responsible for coordinating and promoting BPS reliability in the Western Interconnection. WECC's 329 members, including 38 BAs, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 82 million people, it is geographically the largest and most diverse of the NERC Regional Entities. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. The WECC assessment area is divided into six subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), the Northwest Power Pool (NWPP), and the Canadian areas of Alberta (WECC AB) and British Columbia (WECC BC). These subregional divisions are used for this assessment as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

Highlights

- The Western Interconnection and all the individual subregions are expected to have sufficient generation to meet or exceed the Reference Margin Level during the assessment period.
- The Los Angeles Basin in Southern California continues to be an area of short-term concern due to the reduced availability of the Aliso Canyon natural gas storage facility. WECC continues to study this in conjunction with CAISO and SoCalGas to assess the potential impacts to reliability for the Western Interconnection.
- In 2018, the combined nameplate capacity of all utility-scale resources in the Western Interconnection was 258,200 MW. Approximately 1,300 MW of wind and solar capacity were added, and natural gas capacity increased by 900 MW. Different subregions of the West have different resource portfolios. Hydro units are dominant in the Northwest, while California and the Southwest rely heavily on natural gas. Solar units have become prevalent, especially in California, as wind capacity has grown in the Rock Mountains and along the Columbia River.
- CAISO performed additional analysis that quantified the potential operational shortfall of meeting the 1-in-2 hourly forecast load plus 15% planning reserve margin. Investigating the expected generation production from available wind, solar, and hydro resources across a broader timeframe (i.e. 4:00 p.m. through 9:00 p.m. Pacific Daylight Time, capacity shortfalls were identified to be as high as 2,300 MW in 2020, 4,400 MW in 2021, and 4,700 MW in 2022).

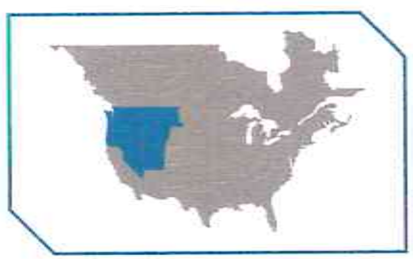
Starting on the next page are summaries of the assessment areas that make up WECC.



WECC-AB

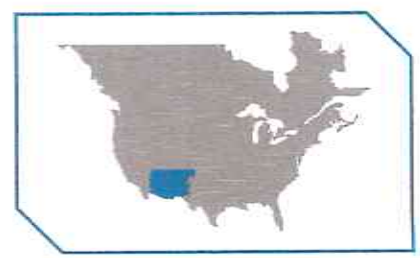
WECC-BC

WECC-CAMX



WECC-NWPP-US

WECC-RMRG



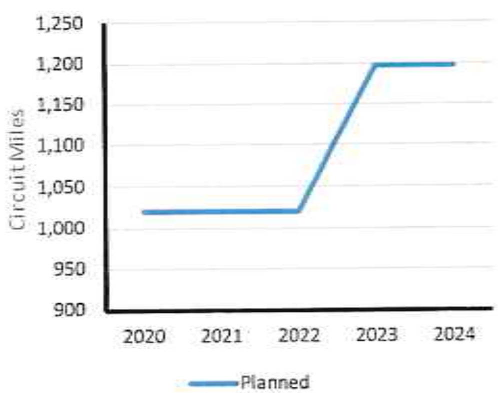
WECC-SRSG

Exhibit Bickett-4

WECC-AB

Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	12,018	11,707	12,144	12,260	12,321	12,113	12,231	12,345	12,814	12,945
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,018	11,707	12,144	12,260	12,321	12,113	12,231	12,345	12,814	12,945
Additions: Tier 1	0	0	0	0	0	0	0	0	0	0
Additions: Tier 2	323	323	323	323	323	323	323	323	323	323
Additions: Tier 3	109	1,145	2,357	3,819	4,036	4,753	5,015	5,423	6,604	7,926
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	14,896	14,896	14,896	14,896	14,896	14,896	14,896	14,896	14,896	14,896
Anticipated Reserve Margin (%)	23.95%	27.24%	22.66%	21.50%	20.90%	22.97%	21.79%	20.66%	16.25%	15.07%
Prospective Reserve Margin (%)	26.64%	30.00%	25.32%	24.14%	23.52%	25.64%	24.43%	23.28%	18.77%	17.57%
Reference Margin Level (%)	10.42%	10.36%	10.28%	10.21%	10.14%	10.05%	9.95%	9.88%	9.80%	9.73%

Demand, Resources, and Reserve Margins (MW)



Projected Transmission Circuit Miles

Planning Reserve Margins

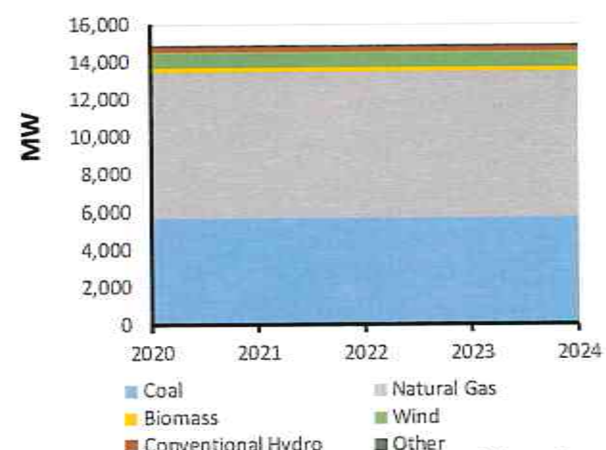


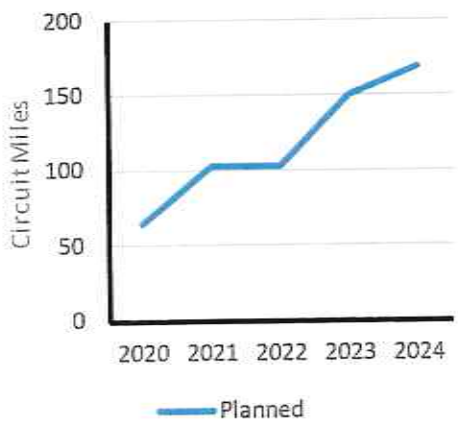
Exhibit Bickett-4

Existing and Tier 1 Resources

WECC-AB Fuel Composition										
Generation Type	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Coal	5,727	5,727	5,727	5,727	5,727	5,727	5,727	5,727	5,727	5,727
Natural Gas	7,735	7,735	7,735	7,735	7,735	7,735	7,735	7,735	7,735	7,735
Biomass	261	261	261	261	261	261	261	261	261	261
Wind	785	785	785	785	785	785	785	785	785	785
Other	78	78	78	78	78	78	78	78	78	78
Total MW	14,896	14,896	14,896	14,896	14,896	14,896	14,896	14,896	14,896	14,896

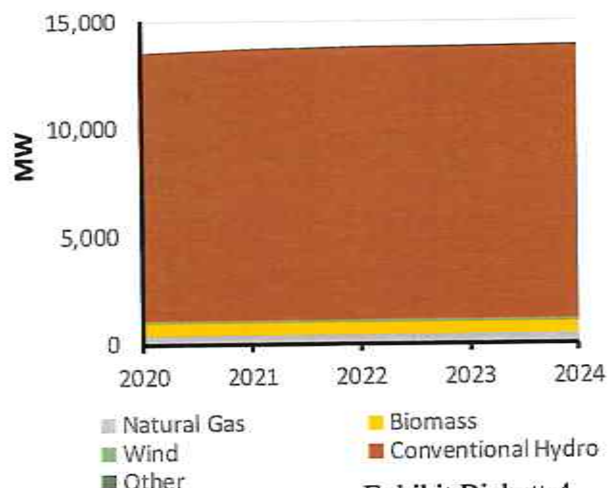
WECC-BC

Demand, Resources, and Reserve Margins (MW)											
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Internal Demand	11,468	11,649	11,828	12,027	12,251	12,430	12,594	12,758	12,965	13,161	13,374
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,468	11,649	11,828	12,027	12,251	12,430	12,594	12,758	12,965	13,161	13,374
Additions: Tier 1	9	250	430	512	532	573	573	614	614	614	614
Additions: Tier 2	0	0	0	0	0	0	825	825	825	825	825
Additions: Tier 3	0	26	96	128	156	232	253	275	671	1,443	1,465
Net Firm Capacity Transfers	0	0	0	0	218	410	580	745	1,000	1,170	1,400
Existing-Certain and Net Firm Transfers	13,284	13,284	13,284	13,284	13,502	13,694	13,864	14,029	14,284	14,454	14,684
Anticipated Reserve Margin (%)	15.92%	16.19%	15.94%	14.71%	14.55%	14.78%	14.64%	14.78%	14.91%	14.49%	14.39%
Prospective Reserve Margin (%)	15.92%	16.19%	15.94%	14.71%	14.55%	14.78%	21.19%	21.24%	21.27%	20.76%	20.55%
Reference Margin Level (%)	10.42%	10.42%	10.36%	10.28%	10.21%	10.14%	10.05%	9.95%	9.88%	9.80%	9.73%



Projected Transmission Circuit Miles

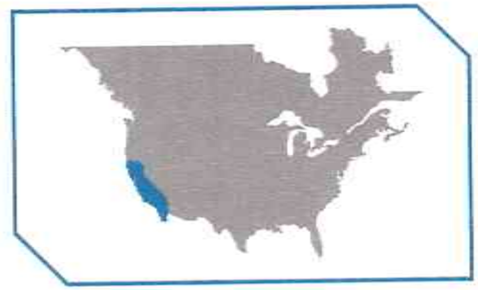
Planning Reserve Margins



Existing and Tier 1 Resources

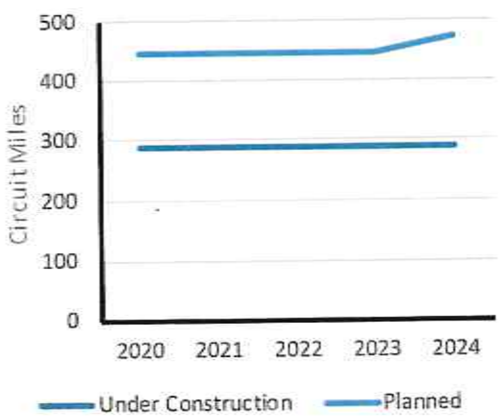
Exhibit Bickett-4

WECC-BC Fuel Composition											
Generation Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Natural Gas	434	434	434	434	442	442	442	442	442	442	442
Biomass	559	559	559	559	559	559	559	559	559	559	559
Wind	82	83	83	83	83	83	83	83	83	83	83
Conventional Hydro	12,207	12,446	12,626	12,708	12,720	12,761	12,761	12,802	12,802	12,802	12,802
Other	13	13	13	13	13	13	13	13	13	13	13
Total MW	13,294	13,534	13,714	13,796	13,816	13,857	13,857	13,898	13,898	13,898	13,898



WECC-CAMX

Demand, Resources, and Reserve Margins (MW)											
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2029
Total Internal Demand	54,214	54,629	54,780	55,173	55,740	56,105	56,394	56,281	56,302	56,777	13,374
Demand Response	910	900	916	905	905	905	905	905	905	905	0
Net Internal Demand	53,303	53,729	53,864	54,268	54,835	55,200	55,489	55,376	55,397	55,872	13,374
Additions: Tier 1	92	470	485	491	941	946	952	1,172	1,172	1,172	614
Additions: Tier 2	2,032	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	825
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0	1,465
Net Firm Capacity Transfers	659	1,427	817	1,216	2,020	2,945	3,050	2,995	3,033	3,560	1,400
Existing-Certain and Net Firm Transfers	62,371	62,383	61,773	62,121	62,481	63,110	63,215	63,095	63,133	63,660	14,684
Anticipated Reserve Margin (%)	17.18%	16.98%	15.58%	15.37%	15.66%	16.04%	15.64%	16.06%	16.08%	16.04%	14.39%
Prospective Reserve Margin (%)	21.00%	20.79%	19.38%	19.14%	19.39%	19.75%	19.32%	19.75%	19.77%	19.70%	20.55%
Reference Margin Level (%)	13.74%	13.87%	13.88%	13.84%	13.91%	13.87%	13.86%	13.89%	13.91%	13.89%	9.73%



Projected Transmission Circuit Miles

Planning Reserve Margins

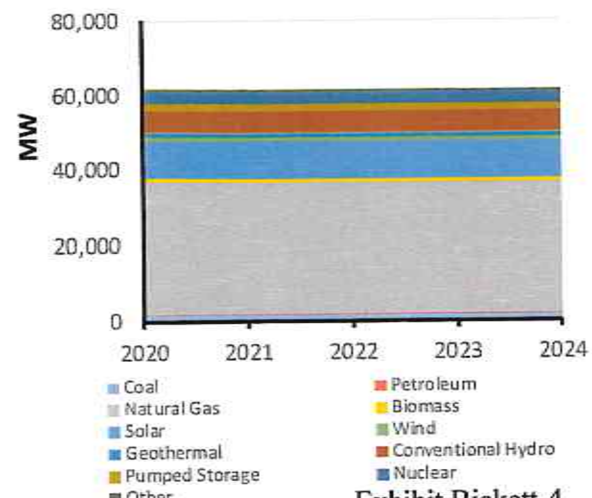
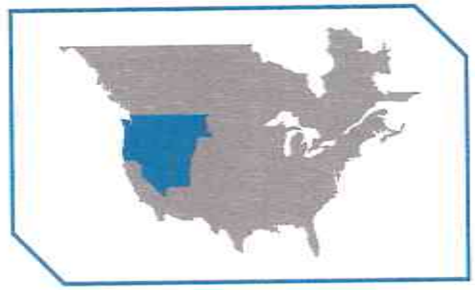


Exhibit Bickett-4

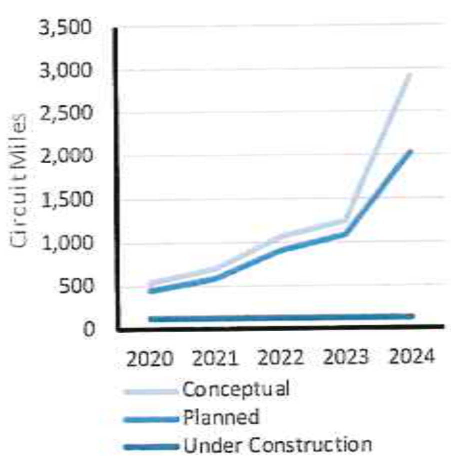
Existing and Tier 1 Resources

WECC-CAMX Fuel Composition										
Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	1,473	1,473	1,473	1,423	1,423	1,423	1,423	1,423	1,423	1,423
Petroleum	242	242	242	242	242	242	242	242	242	242
Natural Gas	35,137	34,680	34,680	34,680	34,680	34,384	34,384	34,534	34,534	34,534
Biomass	1,014	1,036	1,036	1,036	1,036	1,036	1,036	1,036	1,036	1,036
Solar	10,090	10,146	10,162	10,167	10,173	10,178	10,184	10,189	10,189	10,189
Wind	1,097	1,097	1,097	1,097	1,097	1,097	1,097	1,097	1,097	1,097
Geothermal	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176
Conventional Hydro	5,730	5,730	5,730	5,730	5,730	5,730	5,730	5,730	5,730	5,730
Pumped Storage	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Nuclear	3,129	3,129	3,129	3,129	3,129	3,129	3,129	3,129	3,129	3,129
Other	539	539	539	539	539	539	539	539	539	539
Total MW	61,804	61,425	61,441	61,395	61,401	61,111	61,117	61,272	61,272	61,272

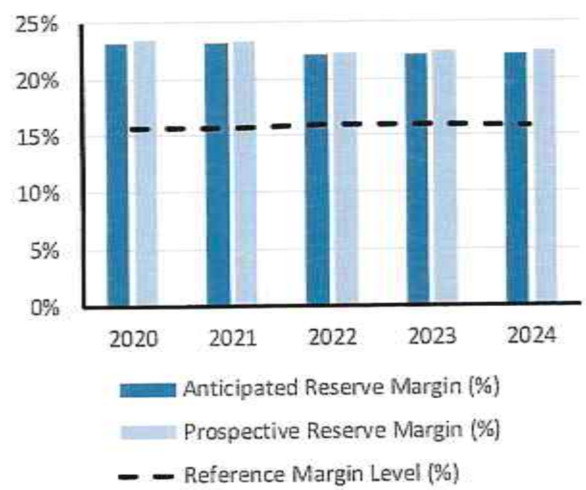


WECC-NWPP-US

Demand, Resources, and Reserve Margins (MW)											
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2029
Total Internal Demand	51,855	51,806	52,489	52,762	52,967	53,263	53,481	53,830	54,091	54,690	13,374
Demand Response	629	653	658	650	652	662	662	676	666	667	0
Net Internal Demand	51,227	51,153	51,831	52,112	52,315	52,601	52,819	53,154	53,425	54,023	13,374
Additions: Tier 1	306	899	1,306	1,336	1,336	1,336	1,336	1,336	1,336	1,336	614
Additions: Tier 2	116	116	116	154	154	154	154	154	154	154	825
Additions: Tier 3	280	341	365	365	383	383	392	992	992	990	1,465
Net Firm Capacity Transfers	749	1,464	1,720	2,278	2,496	3,018	4,258	4,845	5,881	6,508	1,400
Existing-Certain and Net Firm Transfers	62,785	62,070	61,959	62,336	62,554	62,864	63,076	63,441	63,726	64,353	14,684
Anticipated Reserve Margin (%)	23.16%	23.10%	22.06%	22.18%	22.12%	22.05%	21.95%	21.87%	21.78%	21.59%	14.39%
Prospective Reserve Margin (%)	23.39%	23.33%	22.28%	22.48%	22.42%	22.34%	22.24%	22.16%	22.07%	21.88%	20.55%
Reference Margin Level (%)	15.70%	15.69%	15.95%	15.90%	15.84%	15.81%	15.63%	15.51%	15.50%	15.32%	9.73%



Projected Transmission Circuit Miles



Planning Reserve Margins

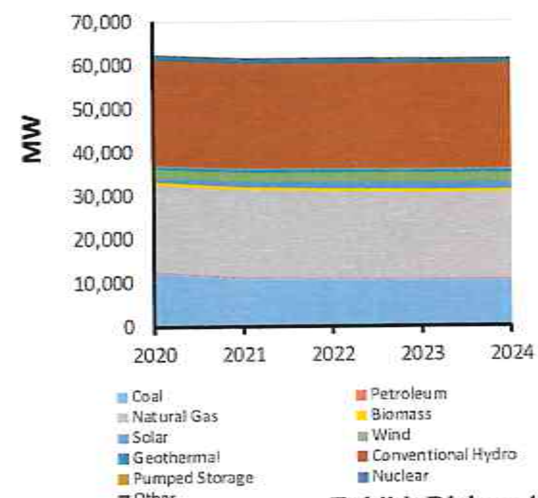


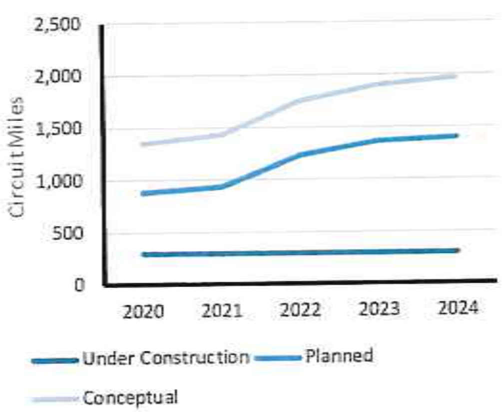
Exhibit Bickett-4

Existing and Tier 1 Resources

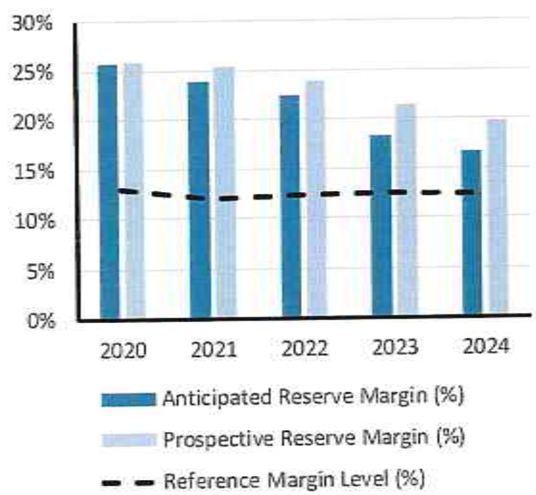
WECC-NWPP-US Fuel Composition										
Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	12,203	10,930	10,676	10,495	10,495	10,495	9,539	9,539	8,788	8,788
Petroleum	152	152	152	152	152	152	152	152	152	152
Natural Gas	20,212	20,162	20,049	20,049	20,049	19,837	19,765	19,543	19,543	19,543
Biomass	749	749	749	749	749	749	749	749	749	749
Solar	883	1,281	1,578	1,608	1,608	1,608	1,608	1,608	1,608	1,608
Wind	2,079	2,124	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214
Geothermal	648	686	706	706	706	706	706	706	706	706
Conventional Hydro	24,042	23,947	23,947	23,947	23,947	23,947	23,947	23,947	23,947	23,947
Pumped Storage	199	199	199	199	199	199	199	199	199	199
Nuclear	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130
Other	44	144	144	144	144	144	144	144	144	144
Total MW	62,342	61,506	61,545	61,394	61,394	61,182	60,154	59,932	59,181	59,181

WECC-RMRG

Demand, Resources, and Reserve Margins (MW)											
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2029
Total Internal Demand	12,982	13,133	13,317	13,494	13,675	13,847	14,044	14,235	14,413	14,597	13,374
Demand Response	240	244	254	258	262	261	261	260	260	259	0
Net Internal Demand	12,742	12,889	13,063	13,236	13,413	13,586	13,783	13,975	14,153	14,338	13,374
Additions: Tier 1	53	77	100	100	100	100	100	100	100	100	614
Additions: Tier 2	4	199	199	411	411	411	411	411	411	411	825
Additions: Tier 3	14	103	103	103	103	103	103	103	103	103	1,465
Net Firm Capacity Transfers	0	0	0	0	0	51	497	750	1,270	1,474	1,400
Existing-Certain and Net Firm Transfers	15,972	15,884	15,884	15,559	15,559	15,610	15,721	15,934	16,144	16,348	14,684
Anticipated Reserve Margin (%)	25.76%	23.84%	22.36%	18.30%	16.75%	15.63%	14.79%	14.73%	14.77%	14.71%	14.39%
Prospective Reserve Margin (%)	25.80%	25.38%	23.88%	21.41%	19.81%	18.66%	17.77%	17.67%	17.68%	17.58%	20.55%
Reference Margin Level (%)	13.00%	12.00%	12.30%	12.46%	12.35%	12.26%	12.15%	11.54%	11.77%	11.69%	9.73%



Projected Transmission Circuit Miles



Planning Reserve Margins

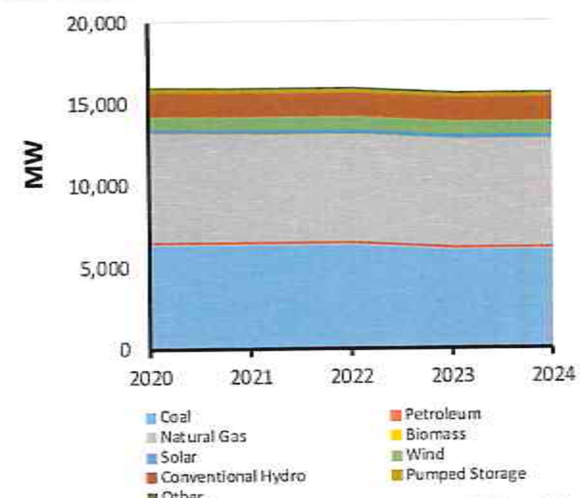


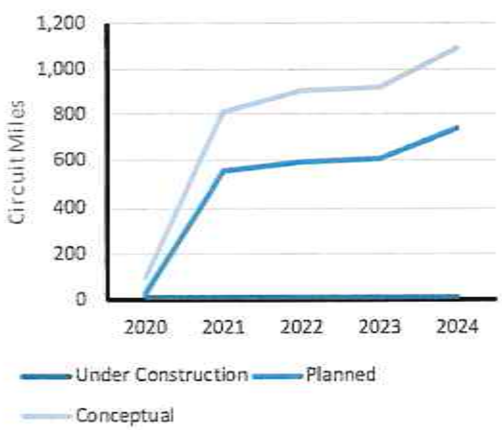
Exhibit Bickett-4

Existing and Tier 1 Resources

WECC-RMRG Fuel Composition										
Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	6,398	6,398	6,398	6,073	6,073	6,073	5,738	5,738	5,738	5,738
Petroleum	155	155	155	155	155	155	155	155	155	155
Natural Gas	6,705	6,617	6,617	6,617	6,617	6,617	6,617	6,577	6,267	6,267
Biomass	3	3	3	3	3	3	3	3	3	3
Solar	180	204	227	227	227	227	227	227	227	227
Wind	774	774	774	774	774	774	774	774	774	774
Geothermal	0	0	0	0	0	0	0	0	0	0
Conventional Hydro	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458
Pumped Storage	282	282	282	282	282	282	282	282	282	282
Other	70	70	70	70	70	70	70	70	70	70
Total MW	16,025	15,961	15,984	15,659	15,659	15,659	15,324	15,284	14,974	14,974

WECC-SRSG

Demand, Resources, and Reserve Margins (MW)											
Quantity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2029
Total Internal Demand	24,571	25,221	25,647	26,136	26,515	26,885	27,633	27,902	28,444	28,785	13,374
Demand Response	144	144	144	144	144	144	144	144	144	144	0
Net Internal Demand	24,427	25,077	25,503	25,992	26,371	26,741	27,489	27,758	28,300	28,641	13,374
Additions: Tier 1	477	542	557	557	557	557	557	557	557	557	614
Additions: Tier 2	200	277	277	717	717	717	717	717	717	717	825
Additions: Tier 3	461	928	1,041	1,554	2,544	2,739	2,764	3,191	3,337	3,337	1,465
Net Firm Capacity Transfers	0	0	340	1,652	1,480	2,430	3,234	3,830	4,601	4,777	1,400
Existing-Certain and Net Firm Transfers	28,963	28,963	29,303	29,802	29,630	30,580	31,384	31,658	32,429	32,605	14,684
Anticipated Reserve Margin (%)	20.52%	17.66%	17.09%	16.80%	14.47%	16.44%	16.20%	16.06%	16.56%	15.79%	14.39%
Prospective Reserve Margin (%)	21.34%	18.76%	18.17%	19.56%	17.19%	19.12%	18.81%	18.64%	19.10%	18.29%	20.55%
Reference Margin Level (%)	10.00%	11.00%	11.00%	11.00%	11.00%	11.00%	9.00%	10.00%	10.00%	10.00%	9.73%



Projected Transmission Circuit Miles

Planning Reserve Margins

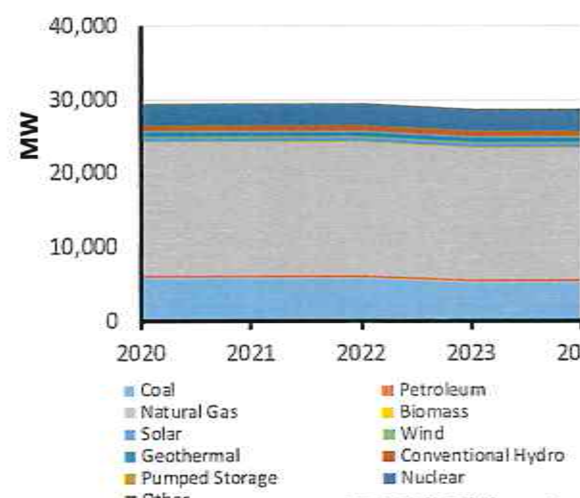


Exhibit Bickett-4

Existing and Tier 1 Resources

WECC-SRSG Fuel Composition										
Generation Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	5,866	5,866	5,866	5,251	5,251	5,251	5,251	5,251	5,251	5,251
Petroleum	307	307	307	307	307	307	307	307	307	307
Natural Gas	18,070	18,070	18,070	17,872	17,872	17,872	17,872	17,550	17,550	17,550
Biomass	89	89	89	89	89	89	89	89	89	89
Solar	458	494	509	509	509	509	509	509	509	509
Wind	203	232	232	232	232	232	232	232	232	232
Geothermal	670	670	670	670	670	670	670	670	670	670
Conventional Hydro	747	747	747	747	747	747	747	747	747	747
Pumped Storage	120	120	120	120	120	120	120	120	120	120
Nuclear	2,859	2,859	2,859	2,859	2,859	2,859	2,859	2,859	2,859	2,859
Other	51	51	51	51	51	51	51	51	51	51
Total MW	29,440	29,505	29,520	28,707	28,707	28,707	28,707	28,385	28,385	28,385

WECC Assessment

Planning Reserve Margins: The ARM does not fall below the Reference Margin level for any year for any of the assessment areas within WECC. WECC uses a probabilistic approach for determining Reference Margin Levels, holding a loss of load probability (LOLP) constant equal to 0.02% (approximately a 1-in-10 loss of load). WECC's model determines what reserve margin must be held to maintain that fixed LOLP. Using this technique, WECC has a target reserve margin for every hour of the year that can be used to assess nonpeak conditions as well as peak conditions. For this assessment, WECC only reported the reserve margins at peak conditions.

Demand: Load forecasts are provided to WECC annually through the loads and resources data request by the 38 individual BAs. The BAs demand and energy forecast are based on expected population growth, economic conditions, and weather patterns. Forecasted demand is reduced for rooftop solar to reflect demand expected to be served by the LSE. The entities report their firm demand to WECC with various elements removed or modeled independently. These include BTM PV, energy efficiency, and DSM program totals. Electric vehicle penetration isn't explicitly reported though it is imbedded into the firm demand in some instances. The underlying assumptions in firm demand are not reported to WECC. WECC staff uses monthly peak and energy data and a historic hourly "base curve" to generate an hourly demand curve (8,760 hours) for each BA for each year 1–10 (2020–2030).

Demand-Side Management: A significant portion of the controllable DR/DSM programs within the Western Interconnection are associated with large industrial facilities, air conditioner cycling programs, and water pumping—both canal and underground potable water for irrigation. These programs are created by LSEs that are responsible for their administration and execution when needed. In some areas, the programs are market driven (CAISO and AESO) and can be called upon for economic considerations. However, most areas in the Western Interconnection are not parties to organized markets, and DSM programs are approved by local authorities and used only for the benefit of the approved LSE. DSM programs in the Western Interconnection often have limitations such as limited number of times they can be called on and some can only be activated during a declared local emergency. Entities within WECC are not forecasting significant increases in controllable DR.

Distributed Energy Resources: A significant portion of the controllable DR programs within WECC are associated with large industrial facilities, air conditioner cycling programs, and water pumping—both canal and underground potable water for irrigation use. These programs are created by LSEs that are responsible for their administration and execution when needed. In some areas, the programs are market driven (CAISO and AESO) and can be called upon for economic considerations. However, most areas in the Western Interconnection are not parties to organized markets, and DSM programs are approved by local authorities and used only for the benefit of the approved LSE. DSM programs in WECC often have limitations, such as limited number of times they can be called on and some can only be activated during a declared local emergency.

Generation: The results from this assessment indicate that all assessment areas are resource adequate in the short, near, and long term with their current resource portfolio plans. However, in November of 2018, the California public utilities commission (PUC) began inquiring about potential near- or medium-term reliability issues. Based on comments and the CPUC's own analysis, the CPUC opened a procurement track within its integrated resource planning proceeding to address an estimated 2,000 MW capacity shortfall from the CPUC resource planning criteria of having sufficient capacity to meet 1-in-2 peak load plus 15% planning reserve margin. In response, the ISO performed additional analysis and filed comments that quantified the potential operational shortfall of meeting the 1-in-2 hourly forecast load plus 15% planning reserve margin. While investigating the expected generation production from available wind, solar, and hydro resources across a broader time frame (i.e. 4:00 p.m. through 9:00 p.m. Pacific), capacity shortfalls were identified to be as high as 2,300 MW in 2020, 4,400 MW in 2021 and 4,700 MW in 2022. As of October 21, 2019, the CPUC issued a revised proposed decision in the IRP procurement track proceeding to authorize 4,000 MW of incremental capacity by August 2023, request for extension of 3,750 MW of once-thru-cooled resources scheduled for retirement for a period of one to three years, and request temporary extension of Moss Landing facility to allow for the facility to meet its OTC compliance obligations. The CPUC is seeking comments on its revised proposed decision with scheduled earliest consideration of the decision by the Commission being November 7, 2019.

The WECC 2028 anchor dataset is a combination power flow and production dispatch model with underlying assumptions (at least on the PCM side) that includes WECC-wide renewable portfolio standard (RPS) targets for the year 2028. The results of that baseline scenario indicate that states with RPS targets meet their renewable goals without additional "gap" resources. The demand curves and resource portfolios used in that scenario are similar to those used in this assessment. This Phase 2 dataset was finalized by WECC's System Adequacy Planning department in June 2019. A reference case analysis of this dataset is currently under development and is not yet public.

Various studies on this dataset are currently under development. Among them are considerations of any potential short-term or long-term challenges associated with state RPS targets, significant penetration of electric vehicles, changes to system inertia with high renewable penetration, natural gas pipeline disruption, and system resiliency under extreme natural disaster.

Exhibit Bickett-4

Variable resource capacity availabilities are based on historic on-peak generation and are aggregated into an assessment area-wide "availability curves." This process involves identifying the expected summer and winter peak hour for each assessment area and year and then applying the availability (percentage of on peak contribution) to the summer or winter rated/reported variable resource capacities. A formal methods and assumptions document is currently under development.

WECC's annual update of the base historical data leads to minor changes in availability curves, but the process itself has not changed for this *2019 LTRA*. The method for counting capacity contribution is the same for all resource tiers, but the variability in historic seasonal peak hour generation may produce different capacity contributions (availability factors) for each assessment year.

WECC studies expected future study cases that include expected generation retirements. Although it is anticipated that older coal-fired resources will retire in coming years, it is not expected that there will be excessive unplanned retirements that cause a severe impact to reliability as these retirements would need approval from state PUCs or ISOs. Individual LSEs and BAs perform retirement studies to determine whether retirements are feasible or to determine the potential impacts to reliability. WECC also develops and compiles 11 base cases to be built for the current year study cycle. Those cases include heavy and light load scenarios that are used by the Transmission Planners and Planning Coordinators to study extreme retirement scenarios.

WECC is not a planning entity and does not approve or reject planned retirements. WECC does incorporate announced or reported planned retirements when creating datasets to be used in their planning models. Retirement of resources is not currently a major concern as ample generations exists in the Western Interconnection. Unexpected or accelerated retirements could pose a concern; however, that is not an anticipated condition during the assessment period.

The large geographic footprint of the Western Interconnection helps mitigate generation retirements with seasonal transfers from winter-peaking areas to summer-peaking areas and vice versa. Transfers are very common in the Western Interconnection.

Capacity Transfers: WECC's assessment process is based on system-wide modeling that aggregates BA-based load and resource forecasts by geographic subregions with conservatively-assumed power transfer capability limits between the zones. The resource adequacy assessment model calculates transfers between the zones limited to the lesser of excess capacity above the margin needed in the transferring zone or the conservative transmission limit. Resources that are physically located in one BA area but are owned by an entity or entities located in another BA's geographic footprint are modeled as remote resources. These resources are modeled with transmission links between the resource zone and the owner's zone that are limited to the owner's share of the resource. This treatment allows the owner of the resource, and only the owner, to count the resource for margin calculations. Remote resources are transferred first in WECC's modeling processes and reduce the capacity available for modeled transfers. The reliability assessments performed by WECC are done with conservative seasonal transfer limits. Therefore, the transfer limits included in the LTRA are studied at less than optimal levels and reflect limited and conservative transfers. Transfers with other regional councils, such as MRO and SPP, are not included in this assessment as this would require an assumption regarding the amount of surplus or deficit generation in those councils.

Transmission: Transmission planning in the Western Interconnection is coordinated by five regional planning groups that create and periodically publish transmission expansion plans: Northern Tier Transmission Group, WestConnect, ColumbiaGrid, California ISO, and Alberta Electric System Operator. Several entities have proposed major transmission projects to connect renewable resources on the eastern side of the Western Interconnection to load centers on the Pacific Coast to help satisfy renewable portfolio standards, particularly in California. These projects, however, are often subject to significant development delays due to permitting and other issues. Currently, it is not anticipated that transmission additions will be needed to maintain reliability in the Western Interconnection during the assessment period, but transmission additions will continue to interconnect renewable resources. Individual LSEs and BAs perform extreme weather scenario studies to determine the potential impacts to reliability. WECC develops the base case compilation schedule that details the 11 cases to be built for the current year study cycle. Those cases include heavy and light load scenarios that are used by the Transmission Planner and Planning Coordinator to study various scenarios.

The System Adequacy Planning department at WECC performs a series of scenarios analysis utilizing production dispatch models to address concerns surrounding transmission limitations and/or constraints.

The System Stability Planning department at WECC performs a series of scenario analysis by utilizing power flow software to address concerns surrounding dynamic and steady state, UVLS, UFLS, RAS, and short-circuit modeling.

WECC's study program, which incorporates analysis of PCM and PF models, is currently under development and includes the following scenarios: path rating process, changes to system inertia with high renewable implementation, natural gas pipeline disruption (most likely in year 10), significant electrification, and system resilience under extreme natural disasters.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[1] for the summer and winter of each year.[2] Projected total internal demand is based on normal weather (50/50 distribution)[3] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[4]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
NPCC-Maritimes	Winter	Noncoincident	Maritimes Sub Areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro Québec
PJM	Summer	Coincident	PJM
SERC-E	Summer	Noncoincident	SERC LSEs
SERC-C	Summer	Noncoincident	SERC LSEs
SERC-SE	Summer	Noncoincident	SERC LSEs
SERC-FP	Summer	Noncoincident	FRCC LSEs
SPP	Summer	Noncoincident	SPP LSEs
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AESO	Winter	Noncoincident	Individual BAs: aggregated by WECC
WECC-BC	Winter	Noncoincident	Individual BAs: aggregated by WECC
WECC-CAMX	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-NWPP-US	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-RMRG	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-SRSG	Summer	Noncoincident	Individual BAs: aggregated by WECC

1 Glossary of Terms Used in NERC Reliability Standards.

2 The summer season represents June–September, and the winter season represents December–February.

3 Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

Exhibit Bickett-4

Resource Categories
NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.
Anticipated Resources • Existing-certain generating capacity: includes operable capacity expected to be available to serve load during the peak hour with firm transmission • Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements • Firm capacity transfers (Imports minus Exports): transfers with firm contracts • Less confirmed retirements[1]
Prospective Resources: Includes all anticipated resources plus the following: • Existing-other capacity: includes operable capacity that could be available to serve load during the peak hour but lacks firm transmission and could be unavailable during the peak or a number of reasons • Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements • Expected (nonfirm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation • Less unconfirmed retirements[2]

1 Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

2 Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- **Existing:** It is in commercial operation.
- **Retired:** It is permanently removed from commercial operation.
- **Mothballed:** It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- **Cancelled:** planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- **Tier 1:** A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power purchase agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- **Tier 2:** A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- **Tier 3:** A units in an interconnection queue that do not meet the Tier 2 requirement

Reserve Margin Descriptions
Planning Reserve Margins: This is the primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile.
Anticipated Reserve Margin: This is the amount of anticipated resources less net internal demand calculated as a percentage of net internal demand.
Prospective Reserve Margin: This is the amount of prospective resources less net internal demand calculated as a percentage of net internal demand.
Reference Margin Level: This is the assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level a can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/ RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels can fluctuate over the duration of the assessment period or may be different for the summer and winter seasons. If a Reference Margin Level is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Recommendations Tracking Matrix

Issue	Recommendation	Responsible	Action/Deliverable	Time line
The ERO recognizes that the changing resource mix, shifting demands, and other factors can have a significant effect on resource adequacy. As a result, the ERO is incorporating more probabilistic methods and other analysis approaches to provide vital and rich insights to effectively assess reliability of the evolving systems with energy-limited and uncertain resources. While the ERO has historically gauged resource adequacy by using solely planning reserve margins focused at peak demand hour, the ERO will expand its use of probabilistic approaches in the 2020 LTRA to support assessment of resource and energy adequacy across all hours.	The ERO should enhance the Reliability Assessment process by incorporating energy adequacy metrics and evaluating scenarios posing the greatest risk.	ERO Staff RAPA-SG Reliability and Security Technical Committee Reliability Assessment Subcommittee Probabilistic Assessment Working Group	Enhancements incorporated in the 2020 Long-Term Reliability Assessment Further enhancements incorporated in 2022 Long-Term Reliability Assessment	Q4 2020 Q4 2022
As more resources are located on the distribution system, it is important that the ERO effectively communicates resource adequacy risk to its state and provincial stakeholders. The ERO's independent and objective assessment is a valuable resource to regulatory and policy making stakeholders that are ultimately responsible for their jurisdictions' resource adequacy and distribution systems. The changing resource mix creates new technical challenges that are complex and complicated, requiring even greater engagement and outreach. The ERO Enterprise, strengthened by NERC and RE engagement at the state and provincial levels, will amplify and enhance outreach toward providing guidance and information to support continued reliable operation of the BPS.	The ERO should increase its communication and outreach with state and provincial policy makers on resource adequacy risks and challenges.	ERO Staff	Enhance and increase participation in NARUC and CAMPUT; work with ERO executive committee to coordinate NERC and Region outreach to state and provincial regulators Animated video shorts to help explain complex topics, such as resource and energy adequacy	Continuous Q3 2020
Given the increased reliance on resources that have a higher level of fuel uncertainty than the previous fleet, system planners should identify potential system risks that could occur under extreme but realistic contingencies and under various future supply portfolios. Proper software applications and modeling are required to support system planners performing these studies.	The ERO should publish Reliability Guidelines, develop requisite tools, and validate models to establish common industry practices for planning and operating the BPS with increasing energy limitations and disruption risks.	ERO Staff Reliability and Security Technical Committee Electric-Gas Working Group	Publish Reliability Guidelines Perform outreach with stakeholders	Q1 2020 Q2 2020

Presently, concerns associated with ramping are largely confined to California. However, as solar generation increases in California and various parts of North America, system planners will need to ensure that sufficient flexibility is available to operators to offset variability and fuel uncertainty.	Industry should identify, design, and commit flexible resources needed to meet increasing ramping and variability requirements.	Industry	Evaluate in future long-term reliability assessments	Continuous
As the penetration of DERs continues to increase across the North American BPS, it is necessary to account for DERs in the planning, operation, and design of the BPS. System operators and planners should gather data as early as possible about the aggregate technical specifications of DERs connected to local distribution grids to ensure accurate and valid system planning device and simulation models, load forecasting, coordinated system protection, and real-time situation awareness. In areas with large or emerging DER penetrations, current operational models and system studies do not properly account for DERs. These models and studies will need to be improved to accurately represent the system's behavior.	The ERO and industry need to work together to ensure system studies incorporate DER impacts.	ERO Staff Reliability and Security Technical Committee System Planning Impacts from DER Working Group Standards Committee	Publish DER Reliability Guideline Consider PC-endorsed SAR for DER Data Publish white paper addressing TPL Reliability Standard issues	Q1 2020 Q2 2020 Q2 2020
Electricity storage has the potential to offer much needed capabilities to the grid of the future. Based on data received in the resource information collected to support this assessment, there will be an increase of BPS-connected storage in the future; this may even be accelerated if the conditions are right. Before this storage is built and integrated into the BPS, the ERO should identify, assess, and report on the risks and potential mitigation approaches to accommodate large amounts of energy storage on BPS reliability.	The ERO should assess the implications of electricity storage on BPS planning and operations.	ERO Staff Reliability and Security Technical Committee	Publish Special Reliability Assessment on impacts, challenges, and opportunities in the large scale integration of electricity storage.	Q4 2020
To accommodate large amounts of variable generation and to meet policy objectives associated with renewables in a reliable and economic manner, more transmission may be needed. For example, to meet the renewable energy requirements, transmission may be required to ensure that transfer of large amounts of energy can be supported when it becomes available. The ERO should assess and evaluate if the decreasing amount of transmission projects presents any future reliability risks or concerns.	In future assessments, the ERO should assess challenges in transmission development and reliability risks due to the changing resource mix.	ERO Staff Reliability and Security Technical Committee Reliability Assessment Subcommittee	Conduct specific assessment of issue within the 2020 Long-Term Reliability Assessment	Q4 2020

Brad Bickett

From:	Brad Bickett
Sent:	Tuesday, July 18, 2017 2:21 PM
To:	Parsley, Marlene
Cc:	Eacret, Mark J
Subject:	RE: planning reserve margin requirement - HMP&L
Attachments:	HMPL capacity in MISO for load by planning year 7-18-17.xlsx

Marlene,

In response to your two points below:

1. In the past, HMPL has not submitted any forecast or Resource Adequacy Plan to MISO, and to the best of my knowledge, the capacity reserved from Station Two by HMPL has never been calculated according to the MISO planning requirements. The load forecast data sent to BREC in the past was developed in compliance with the NERC reliability requirements applicable to HMPL, and did not include a coincident peak. Further, the information was not prepared timely for MISO capacity planning purposes.

2. I don't see any problem with the coincidence factor used by BREC. However, the capacity data from BREC associated with HMPL load does not include any coincidence factor for HMPL prior to the current planning year. See attached spreadsheet with data from BREC using the most recent coincidence factor from your calculation (0.951) applied to HMPL peak data.

As I understand the rules of MISO on this subject, there is no requirement to follow any particular method for resource adequacy. However, the plan as submitted by a Load Serving Entity (such as HMPL) is subject to approval by MISO. For this reason, HMP&L is retaining services of GDS Associates for development of a load forecast and resource adequacy plan for the next planning year. I will keep you updated as we go forward.

Thanks,

Brad

From: Parsley, Marlene [mailto:Marlene.Parsley@bigrivers.com]
Sent: Tuesday, June 27, 2017 4:06 PM
To: Brad Bickett
Cc: Eacret, Mark J
Subject: FW: planning reserve margin requirement - HMP&L

Hello, Brad
It appears you're using a similar, but not identical methodology that we used for calculating HMPL's coincidence factor. I've provided some extra information attached and below to show what I mean. Don't hesitate to reach out for more clarification.

Marlene

I notice 2 major differences when comparing your calculation in the "Henderson PRMR calculation 6-27-17.docx" to the one Big Rivers Supplied in our presentation (copied below along with a few pertinent highlights):

1. 2017 Peak Forecast
   a. HMPL used the one from January, 2017 (108 MW)
   b. Big Rivers used the one in effect at MISO's October 31, 2016 submission date (see attached "HMPL Load Forecast worksheet revised 3-31-16 with monthly data.pdf") (109 MW)
2. Time period for calculating coincidence factor
   a. HMPL used one year (2016)
   b. Big Rivers used the average of 2011-2015 (see table below for our calc.)

The following table shows the values our contractor (GDS) used to compute the coincidence factors for HMPL for Planning Year 2017/18. CP demands represent the average load at the four MISO and MISO/Zone6 peak hours each year. FYI: While our contractor calculated and included in the table a coincidence factor for MISO Zone 6, only the CP with MISO is used for calculating the Planning Reserve Margin Requirement.

HMPL

	1HR Peak	CP with MISO	CF	CP with Zone 6	CF
2011	113	109.1	0.965	109.3	0.967
2012	115	106.5	0.926	107.3	0.933
2013	108	106.0	0.981	105.3	0.975
2014	108	105.3	0.975	104.5	0.968
2015	109	98.8	0.906	103.6	0.950
2016	107				
			0.951		0.959

For your reference, attached are the Historical Peak Dates and Times supplied on MISO's website, as well as a Whitepaper describing what MISO looks for when they review a forecast submitted by an LSE (see page 7 of 14, as well as Appendix A on page 11/14). For the PY 17/18 forecast, Big Rivers used the same forecast methodology that was randomly sampled for review by MISO (I believe it was for PY 13/14) and our forecast was deemed "Acceptable" at that time.

Copied from the previous report Big Rivers supplied to HMPL:

Load and Resource Examples from PY 2017/18:
<u>HMPL's Planning Year 2017/18 Load Obligation:</u>

Annually, Big Rivers must submit a Coincident Peak Demand forecast for the upcoming planning year for loads at Commercial Pricing Nodes by November 1 of the year prior to the planning year. Because HMPL Load is represented within the Big Rivers load commercial pricing node (BREC.BREC), Henderson load is included in the Big Rivers' coincident peak Demand. This year, Big Rivers contracted with GDS to determine the coincident peak demand forecast, and additionally requested a coincidence factor for HMPL load. The HMPL load forecast was determined to be coincident to MISO peak by a factor of .951. Applying the .951 coincidence factor to HMPL's forecasted July 2017 peak of 109 MW (per the forecast that was effective at the November 1, 2016 Peak Demand Forecast due date), the coincident peak load for HMPL is 103.7 MW.

So, for Planning Year 2017/18 the HMPL Planning Reserve Margin Requirement calculation is:

Coincident Peak MW *(1 + Transmission Losses) * (1 +PRM)

Coincident Peak MW	= 103.7 MW
Transmission Losses	= 2.2%
PRM	=7.8%

Requirement = Coincident Peak MW + Transmission Losses + PRMR
Requirement = 103.7 MW * 102.2% *107.8%
Requirement = 114.2 MW

Marlene Parsley
Director, Resources and Forecasting
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42419-0024

270-844-6155 Office
270-577-1617 Cell
Marlene.Parsley@Bigrivers.com

From: Brad Bickett [mailto:bbickett@hmpl.net]
Sent: Tuesday, June 27, 2017 12:33 PM
To: Parsley, Marlene <Marlene.Parsley@bigrivers.com>
Cc: Eacret, Mark J <Mark.Eacret@bigrivers.com>
Subject: planning reserve margin requirement - HMP&L

Marlene,

Thanks again for your help on this resource adequacy topic. I will probably be reaching out to you and/or MISO with additional questions. After looking over the information provided and our data, I attached for your review my quick version of the MISO Planning Reserve Margin Requirement calculation for HMP&L during this current Planning Year.

Brad

Brad Bickett

From: Bradley, Chris [Chris.Bradley@bigrivers.com]
Sent: Friday, January 27, 2017 12:02 PM
To: Brad Bickett
Cc: Parsley, Marlene
Subject: RE: HMP&L Load Forecast - Demand and Energy Data for MOD-031-2

Brad,

Thank you for the information. Please consider this message an acknowledgement of receipt by Big Rivers.

Thank you,

Chris Bradley
Director Energy Control and Compliance
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42420
Direct: 270-844-6201

From: Brad Bickett [mailto:bbickett@hmpl.net]
Sent: Friday, January 27, 2017 11:40 AM
To: Bradley, Chris <Chris.Bradley@bigrivers.com>
Cc: Parsley, Marlene <Marlene.Parsley@bigrivers.com>
Subject: HMP&L Load Forecast - Demand and Energy Data for MOD-031-2

Chris:

See attached load forecast for HMP&L. Look at Section 2 of the document for reference to data in compliance with MOD-031 and the Demand and Energy Data requested from Big Rivers. I understand that Big Rivers requests that this data be provided by February 1st each calendar year; please acknowledge receipt of this email for my records.

Thank you and have a good weekend.

Brad Bickett
Reliability Compliance Manager
Henderson Municipal Power & Light (HMP&L)
100 Fifth Street, Henderson, KY 42420
Phone: (270) 826-2726 Fax: (270) 826-9650

Exhibit Bickett-6

Brad Bickett

From: Bradley, Chris <Chris.Bradley@bigrivers.com>
Sent: Wednesday, January 31, 2018 4:13 PM
To: Brad Bickett
Cc: Ken Brooks; Parsley, Marlene
Subject: RE: HMP&L Demand and Energy Data for MOD-031-2

Brad,

Please consider this an acknowledgment of receipt by Big Rivers. The submittal appears to satisfy all associated requirements.

Thank you,

Chris

From: Brad Bickett [mailto:bbickett@hmpl.net]
Sent: Tuesday, January 30, 2018 9:04 AM
To: Bradley, Chris <Chris.Bradley@bigrivers.com>
Cc: Ken Brooks <kbrooks@hmpl.net>; Parsley, Marlene <Marlene.Parsley@bigrivers.com>
Subject: HMP&L Demand and Energy Data for MOD-031-2

Chris:

Big Rivers requests data be provided pursuant to Requirement R1 of MOD-031-2 before February 1st each year. See attached PDF document that includes HMP&L data and information requested in the BREC data request spreadsheet. Let me know if you have any comments or questions.

Please acknowledge receipt of this email for my records.

Thanks,

Brad Bickett
Reliability Compliance Manager
Henderson Municipal Power & Light (HMP&L)
100 Fifth Street, Henderson, KY 42420
Phone: (270) 826-2726 Fax: (270) 826-9650

Henderson Municipal Power & Light

May 25, 2018

Mark Eacret
Vice President Energy Services
Big Rivers Electric Corporation
201 3rd Street
Henderson, KY 42420

Re: Notice of Capacity Deficiency

Dear Mark,

In response to your letter of May 22, 2018, HMP&L disagrees with Big Rivers' assertion that HMP&L's current capacity reservation does not meet MISO adequacy requirements, and disagrees with Big Rivers' calculation suggesting that HMP&L currently is deficient by eight (8) Zonal Resource Credits (ZRCs). HMP&L further disagrees with Big Rivers' interpretation of the Power Sales Contract, and the System Reserves Agreement as referenced in your letter.

However, as a strictly precautionary measure, and to alleviate any concern regarding the sufficiency of HMP&L's reservation under MISO requirements, HMP&L is in the process of executing a contract to purchase eight (8) Zonal Resource Credits, which are to be credited to Big Rivers' portal in MISO effective June 1, 2018.

HMP&L's purchase of additional capacity is not to be construed as an acceptance or endorsement of Big Rivers' position concerning the adequacy of HMP&L's capacity reservation, the appropriate method for calculating reserved capacity, and/or the interpretation of the Power Sales Contract and/or System Reserves Agreement.

Sincerely,

Chris Heimgartner
General Manager, Henderson Municipal Power and Light

Exhibit Bickett-8

100 FIFTH STREET P.O. BOX 8 HENDERSON, KENTUCKY 42419-0008 (270) 826-2726 FAX (270)826-9650