NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2020 Probabilistic Assessment

Regional Risk Scenario Sensitivity Case

June 2021

RELIABILITY | RESILIENCE | SECURITY




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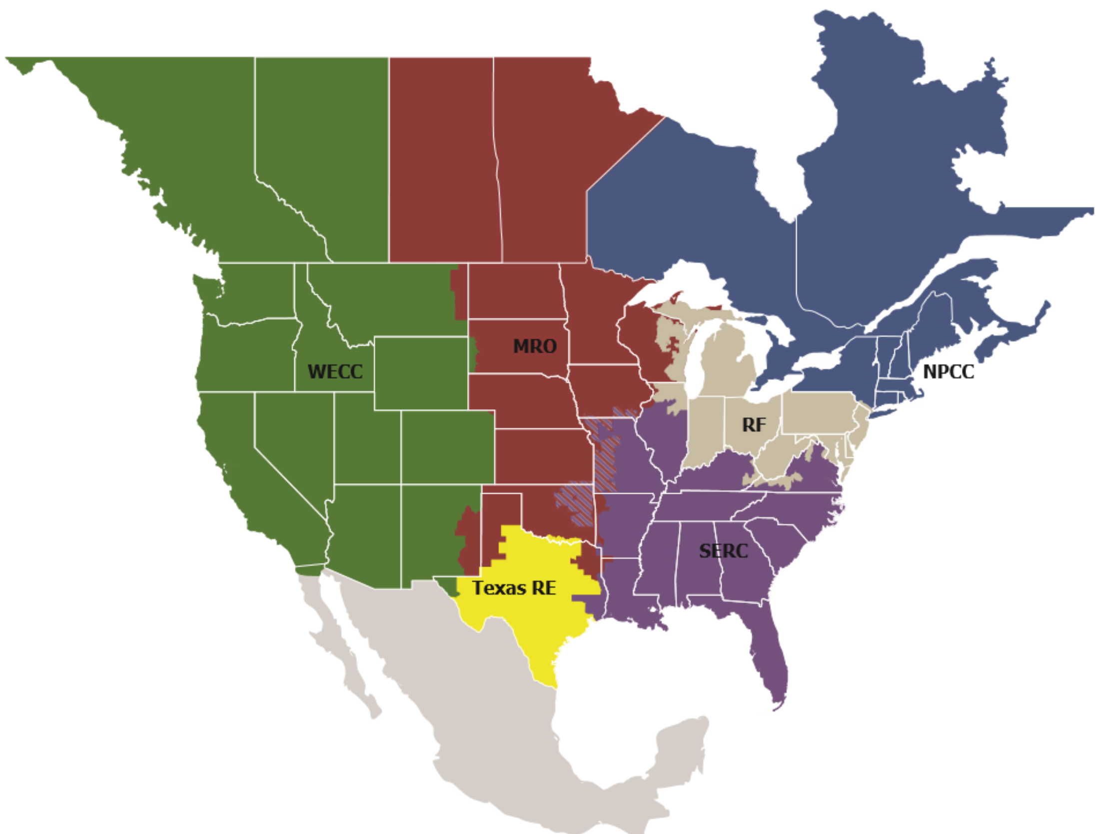
Preface

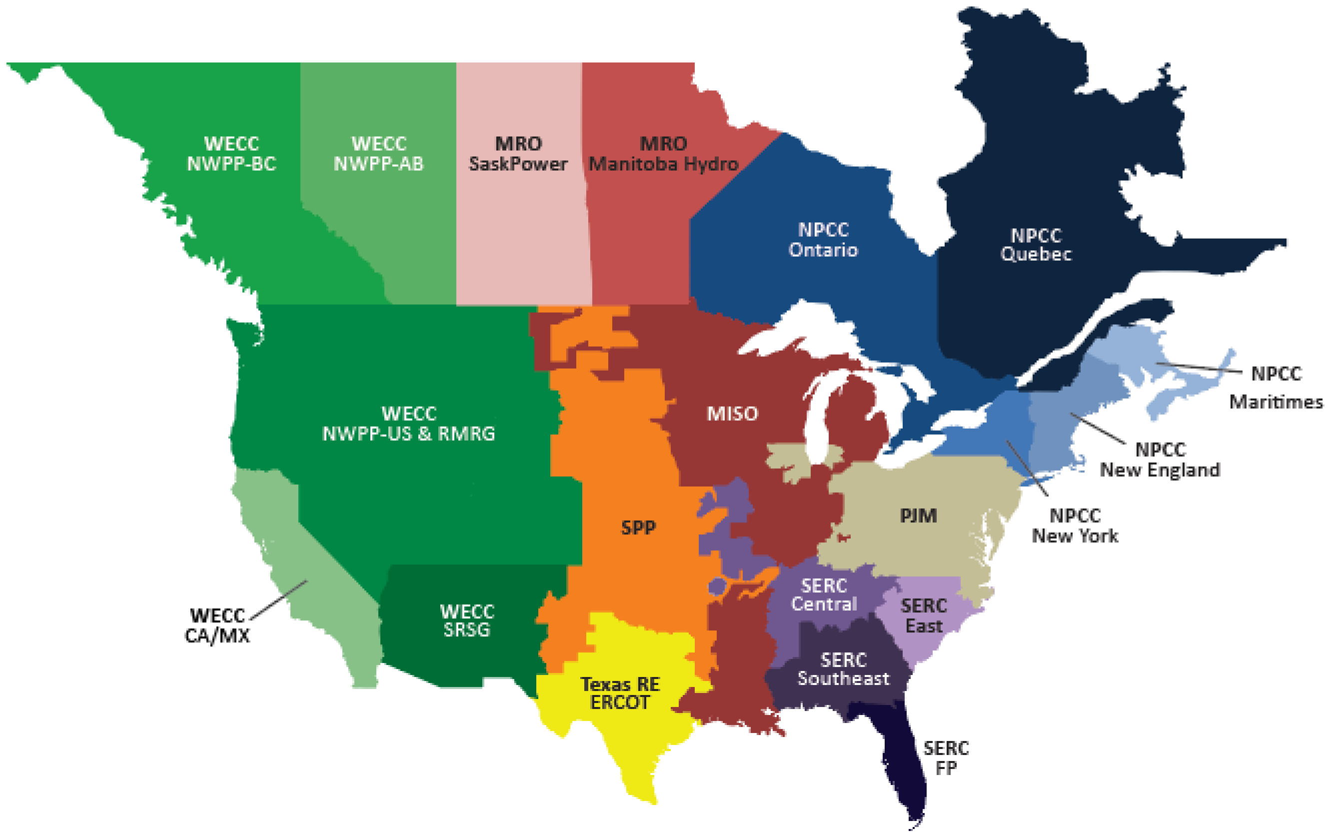
Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our 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 made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC



MRO – Midwest Reliability Organization
- MISO
- MRO-Manitoba Hydro
- MRO-SaskPower
- SPP

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT

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

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

RF – ReliabilityFirst
- PJM

SERC – SERC Reliability Corporation
- SERC-East
- SERC-Central
- SERC-Southeast
- SERC - Florida Penninsula

Executive Summary

Over the past decade, variable energy resources are steadily replacing conventional forms of generation. Considering the changing resource mix, NERC has increasingly used probabilistic assessments as tools to identify potential reliability risks in industry plans. With various resource portfolios and distinct plans to meet electricity reliability requirements across the Bulk Electric System (BES) and the BPS, the NERC Probabilistic Assessment Working Group (PAWG) recognizes that each RE may have unique risks to consider and assess. This assessment describes the assessments of regional risk scenarios. This change from historic PAWG procedures that emphasized a uniform study of one particular risk allowed system planners to more closely study area-specific reliability risks and their uncertainties by using probabilistic methods. It is important to recognize that the BES (and the BPS by extension) is diverse in terms of planning and operations processes as well as associated risks across the NERC REs and assessment areas. This assessment utilized a comprehensive and peer-review process for each assessment area's respective methods, assumptions, and results.

The REs were requested to compare the purported risk factor results in the ProbA Sensitivity Case[1] to the ProbA Base Case results from the *2020 NERC LTRA*[2]. These comparisons between the Base and Sensitivity Cases, combined with the trending results compared from the 2018 ProbA (found in the *2018 NERC LTRA*), provide a complete analysis to better understand underlying uncertainties and benchmark system risks. At RE discretion, the scenarios intentionally stressed the study assumptions in order to assess their associated impacts on the probabilistic indices. Although mitigation efforts were not the intended focus of the study, some REs provided rationales on expected methods to mitigate against the risk their chosen scenario assessed.

The Sensitivity Case scenarios include the following:

- **MISO (MRO):** Increased demand response (DR) as a percentage of the overall resource mix
- **Manitoba Hydro (MRO):** Variations in low water conditions with external assistance limitations
- **SaskPower (MRO):** Impact of low hydro conditions on its system reliability
- **SPP (MRO):** Low wind resource output with an increase in conventional generation forced outages
- **NPCC:** Planned/expected future capacity or resources may not materialize
- **PJM (RF):** Planned/expected future capacity or resources may not materialize
- **SERC:** Impact of planned maintenance outage on system risk
- **ERCOT (TRE):** Impacts of a difference in the realized frequency of high load and low wind output events
- **WECC:** Impacts to resource adequacy associated with potential coal-fired generation retirements

Key Findings

Sensitivity results were varied across the study and dependent on their underlying assumptions. In some assessment areas (i.e., Manitoba Hydro, SaskPower, PJM, all assessment areas of NPCC), the study demonstrated that the risks were not significant, did not impact the probabilistic indices, and/or could be mitigated using preventive planning and operating measures. Other assessment areas noted potential risks if the chosen scenario was to materialize under the sensitivity assumptions. SPP determined loss of load hours (LOLH) and expected unserved energy (EUE)[3] increases

[1] The term "Sensitivity Case" refers to a different set of assumptions, model practices, or other alterations performed to augment the study of a risk identified in the Base Case that is included in the LTRA. Historically, the Sensitivity Case was uniform across all REs, akin to the Base Case.
[2] NERC_LTRA_2020.pdf
[3] For information on interpreting the values of EUE and LOLH used to evaluate the scenarios, see NERC PAWG Probabilistic Adequacy and Measures Report

in their scenario mostly occurring on or around the peak hour. SERC also noted low to moderate increases in their loss of load (LOL) indices from the Base Case associated with maintenance outages, noting an emphasis and need to adequately plan outage windows accordingly. WECC found that, in many assessment areas across the Western Interconnection, the advanced retirement of coal units either dramatically increases or negligibly increases the LOLH or EUE. Results were also dependent on the amount of available external assistance between assessment areas and the penetration of coal resources in their respective portfolios. High level results of the regional risk scenarios performed by assessment areas can be found in **Table ES.1**. To understand the results in **Table ES.1**, see each assessment area's section of the report for the comparison of these values to the Base Case ProbA results as well as any additional references provided in **Appendix E**.

Table ES.1: Summary of Regional Risk Scenario for Each Assessment Area[4]

Assessment Area	2022 Expected Unserved Energy [MWh/yr]	2022 Loss of Load Hours [hrs/yr]	2024 Expected Unserved Energy [MWh/yr]	2024 Loss of Load Hours [hrs/yr]
MRO				
MISO[5]	N/A	N/A	27.69	0.24
Manitoba Hydro	45.13	1.79	0.05	0.06
SaskPower	319.20	3.50	59.70	0.60
SPP	N/A	N/A	72.60	0.11
NPCC				
New England	5.30	0.01	88.10	0.14
Maritimes	4.16	0.08	6.72	0.13
New York	0.68	0.00	13.90	0.05
Ontario	0.09	0.00	79.96	0.14
Québec	0.00	0.00	0.00	0.00
RF				
PJM	0.00	0.00	0.33	0.00
SERC[6]				
Central	N/A	N/A	12.20	0.02
East	N/A	N/A	517.40	0.57
Southeast	N/A	N/A	7.50	0.01
Florida Peninsula	N/A	N/A	513.30	0.52
Texas RE				
ERCOT[7]	N/A	N/A	64.72	0.05
WECC				
BC	0.00	0.00	0.00	0.00
AB	0.00	0.00	0.00	0.00
CA/MX[8]	1,005,716	31.80	2,402,976	70.70
SRSG	212	14.70	437	22.00
NWPP-US	14,681	0.28	274,091	6.20

[4] An "N/A" is denoted where the assessment area chose not to perform the risk scenario for the optional study year.

[5] MISO's scenario has many different amounts of demand response entered in 2024. This table uses the maximum demand response added in their scenario.

[6] SERC performed an extensive stressing of their system to start at a higher LOLE than from the Base Case and performed many different multiplications of their capacity on maintenance. This table uses the maximum reported EUE and LOLH at the extreme scenario.

[7] ERCOT's scenario contained many different load draws. The one that produced the highest EUE and LOLH are presented in this table.

[8] See the Western Assessment in Appendix E for detailed assumptions, findings, and recommendations over what is reported in this document.

Recommendations

With an increasing amount of uncertainty expected on the BPS with regional resource transitions, the PAWG recommends further increasing the use of probabilistic methods and scenarios to adequately study the reliability risks and to determine the sensitivity of those risks for various scenarios. The PAWG also recommends increasing the coordination between industry operations and planning personnel to further develop assumptions for probabilistic reliability assessments. These collaborations and studies could better inform, strengthen, and reinforce the fundamental BPS planning and operations processes to meet future reliability needs.

Introduction

The primary function of the NERC Probabilistic Assessment Working Group (PAWG) is to advance and support probabilistic resource adequacy efforts of the ERO Enterprise in assessing the reliability of the North American Bulk Power System. The group's origins and ongoing activities stem from work initiated by the Probabilistic Assessment Improvement Task Force (PAITF)[9] with the Probabilistic Assessment Improvement Plan.[10] Specifically, the group researches, identifies, and details probabilistic enhancements applied to resource adequacy. The group's long-term focus addresses relevant aspects of the ERO Enterprise Long-Term Strategy[11] and the Reliability Issues Steering Committee (RISC) report[12] in conjunction with the NERC Reliability Assessment Subcommittee (RAS).

NERC regularly utilizes reliability assessments to objectively evaluate the reliability of the North American BPS. On a biennial basis, the NERC PAWG performs a ProbA to supplement the annual deterministic NERC long-term reliability assessment (LTRA) analysis. The ProbA calculates monthly EUE and LOLH[13] indices for Years 2 (Y2) and 4 (Y4) of the 10-year LTRA outlook (2022 and 2024 for the *2020 NERC LTRA*,[14] respectively) and contains two studies: the Base Case and the Sensitivity Case. The two differ in that the Base Case contains assumptions under normal anticipated operating conditions with peer-reviewed study results by the NERC PAWG, the NERC RAS, and the NERC Reliability and Security Technical Committee (RSTC) to ensure comparisons made in the LTRA can be applied across entities. Complete details and underlying assumptions of the 2020 ProbA Base Case analysis were included in the *2020 NERC LTRA,* published in December 2020. The Sensitivity Case provides NERC a way to characterize more "what-ifs" in terms of the probabilistic methods used in each RE. For the 2020 ProbA Sensitivity Case, the PAWG developed a regional risk scenario approach specific to each assessment area. Each RE and assessment area has varied resource mixes, leading to different study focuses between assessment areas. The assessment areas identified and studied respective risk factors to better understand the reliability implications across all hours (instead of just the peak hour) using probabilistic methods. The PAWG believes this approach to be of higher value than standardizing a Sensitivity Case study to capture the varied and complex reliability risks across the BPS. Y2 and Y4 indices were reported for the Base Case study. For the Sensitivity Case, assessment areas were required to perform the analysis on Y4 and Y2 was optional.

Chapters in this assessment are primarily divided by the regional risk scenario chosen for the 2020 ProbA. While regional risk scenarios represent an analysis into potential reliability risk factors, there is no guarantee or indication that these scenarios are indicative of future occurrences. These results are used to inform system planners and operators about potential emerging reliability risk. The PAWG intends to utilize these study results in future probabilistic resource adequacy studies (such as trending applications) to develop further guidance for future work activities, where prominent key points and takeaways are called out.

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[9] Probabilistic Assessment Improvement Task Force (PAITF)
[10] Probabilistic Assessment Improvement Plan
[11] See Focus Areas 1 and 4: ERO Enterprise Long-Term Strategy
[12] See Risk 1: Reliability Issues Steering Committee (RISC)
[13] NERC PAWG Probabilistic Adequacy and Measures Report
[14] NERC_LTRA_2020.pdf

Chapter 1: MRO-MISO

MISO is a summer-peaking system that spans 15 states and consists of 36 local balancing areas that are grouped into 10 local resource zones (LRZs). For the *2020 NERC ProbA*, MISO utilized a multi-area modeling technique for the 10 LRZs internal to the MISO footprint. Firm external imports and non-firm imports were also modeled within the cases.

Key Assessment Takeaway

MISO found that, as the percent of demand response resources increased in their system, their reliability indices could double or triple. This is due to the need to call on demand response more and earlier in the year, leaving them unavailable for future calls in the year.

Risk Scenario Description

For the 2020 ProbA risk scenario, MISO performed a sensitivity analysis that examined the effects of increasing DR resources as a percentage of the overall resource mix. Over the past several years, the amount of DR in MISO has been steadily increasing. For DR to qualify as a capacity resource in MISO, it must be available for a minimum of five calls per year and four hours per day. These minimum dispatch requirements make up much of the DR that currently participates in MISO's capacity market.

MISO conducts a loss of load expectation (LOLE) study annually to determine the amount of reserves required to meet the 1-day-in-10-years LOLE standard. In this study, each individual DR resource in MISO is modeled with their registered dispatch limits. There are cases in that analysis where all the available dispatches for DR would be used and load shed occurred as a result. This discovery prompted a desire to further investigate the effect that dispatch-limited DR has on reliability. See **Appendix E** for details on where to find the report.

To perform this analysis, MISO began from the 2024 Base Case ProbA scenario. DR totaling 5,000 MW was then added to the resource mix in increments of 1,000 MW evenly distributed among the 10 LRZs while simultaneously removing 1,000 MW of generation. Doing this allowed MISO to examine how the risk changes from the Base Case as DR makes up an increasing amount of reserves.

Base Case Results

MISO's Base Case results, reproduced here, show a small amount of EUE and LOLH which is consistent with past ProbA results. Since MISO is a summer peaking system, most of the risk occurs during the summer months (June–September) as expected. However, there are cases where off-peak risk occurs due to certain zones being import limited[15] during periods of high planned outages.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**21.6%**	**17.6%**
Reference	**18.0%**	**18.0%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**27.3**	**14.3**
EUE (ppm)	**0.038**	**0.020**
LOLH (hours/year)	**0.196**	**0.085**

Risk Scenario Results

Currently, DR makes up roughly 4.9% of the total resource mix in MISO. This percentage is reflected in the Base Case results and served as a starting point for the Risk Scenario study. From that starting point, an additional 5,000 MW of DR was added to the system in increments of 1,000 MW. The percentage of DR to the overall resource mix can be found in **Table 1.1**.

[15] Detailed studies on these hours are found in the report linked in Appendix E

Table 1.1: Demand Response Percentage of Overall Resource Mix	
Demand Response Added [MW]	**Percent of Overall Resource Mix [%]**
Base Case	4.9%
1,000	5.5%
2,000	6.1%
3,000	6.8%
4,000	7.4%
5,000	8.1%

EUE and LOLH values were recorded for each iteration of increasing DR. As shown in **Figure 1.1**, when DR increases as a percentage of total resources, EUE and LOLH also increase. By the time an additional 5,000 MW of DR was added, the EUE had nearly doubled and LOLH nearly tripled when compared to the Base Case. The increased risk is driven by the dispatch limits of DR. As previously mentioned, most DR in MISO is only available for five calls per year and four hours per day. As DR begins to make up more of the resources on the system, these resources most likely will exhaust their dispatch limits sooner and become unavailable for the remainder of the year. Historically, DR in MISO was credited in the capacity market solely based on its registered MW. Recently, MISO implemented enhanced accreditation rules for DR that considers dispatch limits and lead times, allowing MISO to more effectively access the capabilities of DRs to maintain system reliability. As the RE's risk profiles continue to evolve with the changing resource mix, MISO is continuously enhancing its resource adequacy planning process and is looking into subannual planning approach to sufficiently capture and mitigate risks across the year.

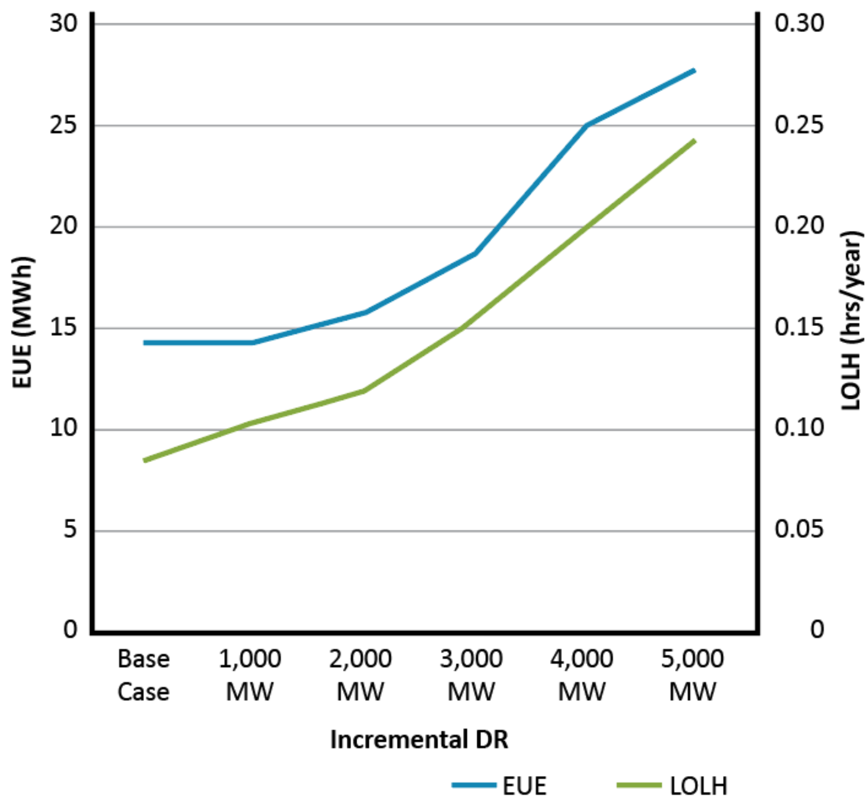

Figure 1.1: MISO Regional Risk Scenario EUE and LOLH[16]

[16] Note that the EUE and LOLH shown here increase as DR replaces traditional generation in increments of 1,000 MW

Chapter 2: MRO-Manitoba Hydro

Manitoba Hydro (MH) system has approximately 6,900 MW (nameplate) of total generation. The system is characterized by around 4,350 MW of remote hydraulic generation located in northern Manitoba and connected to the concentration of load in southern Manitoba via the Nelson River HVdc transmission system. MH also has about 1,858.4 MW of hydraulic generation distributed throughout the province. In addition, 258.5 MW of wind generation and 412 MW thermal generation are distributed in the southern part of the province. The MH system is interconnected to the transmission systems in the Canadian provinces of Saskatchewan and Ontario and the U.S. states of North Dakota and Minnesota.

Key Assessment Takeaway

Manitoba Hydro's reliance on hydro facilities can be susceptible to low-water conditions for a given year. This is mitigated by proper management of reservoirs.

The 2020 NERC ProbA for the MH system was conducted by using the multi-area reliability simulation (MARS) program developed by the General Electric Company. The reliability indices of the annual LOLH and the EUE for 2022 and 2024 were calculated by considering different types of generating units (thermal, hydro and wind), firm capacity contractual sales and purchases, non-firm external assistances, interface transmission constraints, peak load, load variations, load forecast uncertainty, and demand side management programs. The data used in the MARS simulation model are consistent with the information reported in the 2020 LTRA submittals from MH to NERC. On a winter accredited capacity basis, the resources within Manitoba are 92.76% hydro, 0.84% wind, and 6.41% thermal.

Risk Scenario Description

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast, DRs, energy efficiency and conservation programs, wind penetration, and generation fleet availability.

The vast majority of MH's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2020 assessment, MH has examined the impact of the most significant factor variations in water conditions over the long run as detailed in the following:

- Analyze the system as is to establish base reliability indices (Base Case)
- Variations in water conditions: model a 10-percentile low-water condition and report the indices

All hydro units are modeled as Type 2 energy limited units in MARS.[17] The MARS input parameters for each hydro power plant are installed/in-service and retirement dates, monthly maximum and minimum output of each plant and monthly available energy from each plant. Each energy-limited hydro unit is scheduled on a monthly basis. The first step is to dispatch the unit's minimum rating for all of the hours in the month. The remaining capacity and energy are then scheduled as needed as a load modifier during the Monte Carlo simulation.

[17] Type 2 units in the MARS program are "energy-limited units are described by specifying a maximum rating, a minimum rating and a monthly available energy" as stated in their program manual

Base Case Results

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**16.6%**	**16.0%**
Reference	**12%**	**12%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**2.7077**	**3.3831**
EUE (ppm)	**0.1072**	**0.1329**
LOLH (hours/year)	**0.0033**	**0.0039**

The Base Case LOLH values calculated for the reporting year of 2022 and 2024 are virtually zero. Non-zero EUE is obtained, but these values are small. These results are mainly due to the larger forecast reserve margin and the increase in the transfer capability between Manitoba and the United States due to the addition of the new 500 kV tie line between Manitoba and Minnesota. The Base Case LOLH and EUE values calculated in this assessment for the reporting year of 2022 increase slightly from those zero values obtained in the 2018 assessment for the reporting year of 2022. This is expected due to modeling improvements and assumption changes. The most significant model improvement for the 2020 ProbA is that Manitoba Hydro modeled seven different load shapes by using actual historical data to capture the uncertainties associated with load profiles and peak load forecast. In the 2018 assessment, only a typical year load profile was used to model the annual load curve shape.

Risk Scenario Results

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**45.13**	**56.38**
EUE (ppm)	**1.7870**	**2.2150**
LOLH (hours/year)	**0.0544**	**0.0643**

Hydro flow condition is the most significant parameter that characterizes Manitoba Hydro's system resource adequacy. In the 2020 assessment, Manitoba Hydro has examined variations in water conditions in the scenario analysis. Scenario analysis results show that LOLH and EUE values increase for both 2022 and 2024 when an extreme drought scenario is modeled. Water flow conditions of the tenth percentile or lower tend to increase the loss of load hours and expected unserved energy. As a small winter peaking system on the northern edge of a large summer peaking system (i.e., MISO), there is generally assistance available, particularly in off-peak hours, to provide energy to supplement hydro generation in low-flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low-water flow conditions.

Chapter 3: MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of approximately 652,000 square kilometers (251,739 square miles) with approximately 1.2 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. SaskPower is the principal supplier of electricity in the province and responsible for serving over 540,000 customer accounts. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan electric system and its interconnections

Key Assessment Takeaway

SaskPower's lower quartile hydro scenario increases the risk due to higher Reliability Indices, as expected, but did not rise significantly. Such increases can be mitigated by reliance on emergency procedures, if required.

Risk Scenario Description

SaskPower analyzed the impact of low-hydro conditions on its system's reliability. The low hydro forecast is based on 25th percentile hydro flow conditions. Hydro units constitute approximately 20% of Saskatchewan's net installed generation capacity and it hasn't experienced significantly low-hydro conditions since 2001. The area consists of three main river systems, so one river system experiencing low flow conditions doesn't necessarily indicate that the other systems would experience the same conditions. Although there is low probability of low flow conditions experienced by all the river systems in the same year, the sensitivity scenario tests the system's resiliency when the hydro units have less energy for dispatch and subsequently limited peak load shaving capability. Furthermore, this risk scenario has become more relevant since the Saskatchewan government announced in July 2020 that it intends to pursue a $4 billion irrigation project at Lake Diefenbaker that could impact the future water flows available for hydro generation by SaskPower by limiting the water flow and thus energy available for such generation.

The methodology used to derive the various hydro conditions is based on the historical hydrological records in the basin. Before using these historical hydrological records to model any flow scenarios, adjustments were applied to these records that include historical and present upstream water uses, changes in water management, and naturalized flow records if necessary. The long-term forecasts typically use low (lower quartile), best (median) and high estimate (upper quartile) flows based on the current level of development adjusted historical records. Hydro units are modelled as Type 2 energy limited units in MARS. The median quartile hydro conditions in the Base Case were replaced with lower quartile hydro conditions for the sensitivity scenario.

Base Case Results

Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirements for the assessment period. The major contribution to the LOLH and EUE is in the off-peak periods due to maintenances scheduled for some of the largest units.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**34.2%**	**30.0%**
Reference	**11%**	**11%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**80.4**	**26.4**
EUE (ppm)	**3.34**	**1.07**
LOLH (hours/year)	**0.96**	**0.28**

SaskPower did further analysis that changed some of the fixed unit maintenances in year 2022 and let the model schedule them automatically to lower system risk of loss of load. Changing the unit maintenances reduced EUE by more than 50%. Most of the maintenances are scheduled during off-peak periods and can be rescheduled to mitigate identified short-term reliability issues.

Since the 2018 ProbA, the reported forecast reserve margin for 2022 has increased, mainly due to reductions in the load forecast.

Risk Scenario Results

As expected, modelling hydro units with lower quartile hydro conditions results in higher loss of load values as compared to the Base Case; however, this increase in the LOLH and EUE is not anticipated to cause any reliability issues. Since the difference in LOLH and EUE values between the Base Case and Sensitivity Case is quite low, its affects can be mitigated using emergency assistance if needed.

Sensitivity Case summary of Results

	2022	2024
EUE (MWh)	**319.2**	**59.7**
EUE (ppm)	**13.2**	**2.4**
LOLH (hours/year)	**3.5**	**0.6**

Chapter 4: MRO-SPP

The 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 assessment area is reported based on the Planning Coordinator footprint, which 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.

The SPP assessment area has over 90,000 MW (nameplate) of total generation that includes over 28,000 MW of nameplate wind generation. SPP is also a summer peaking assessment area at approximately 51,000 MW of summer peak demand.

Key Assessment Takeaway

Southwest Power Pool demonstrated that many low probability events overlaid can impact their Reliability Indices. A significant increase in forced outage rates, coupled with a low wind output, on a hot summer day can create the conditions for increased risk to EUE and LOLH. This scenario resulted with over 99% of the potential risk identified that occur during summer peak load hours and demonstrated a higher loss of load risk between the scenario studied and the Base Case.

Risk Scenario Description

SPP has seen an increase in installed wind and a slight increase in forced outage rates over the past few years. Therefore, SPP chose a low-wind output scenario paired with an increase in conventional forced generation outages as the 2020 probA regional risk scenario. The historical weather year chosen was the lowest capacity factor output on 2012–2019 summer peak hours to model a low wind scenario. When determining the lowest performing wind year, only peak hours (hour ending 1:00–8:00 p.m.) during months June, July, and August were analyzed to derive the average capacity factor by year. Through this analysis, 2012 wind year was modeled with each historical load year (2012 to 2019) in the risk scenario. The weighted forced outage rate of the Base Case study was approximately 12.5%. The weighted forced outage rate for all conventional resources were increased proportionally and applied to each resource to achieve an SPP weighted forced outage rate of 15%. The regional risk scenario was performed on year 2024 to reflect additional generation retirements and projected installed wind capacity.

Base Case Results

No loss of load events were indicated for the Base Case study due to a surplus of capacity in the SPP assessment area. Reserve margins are well above 20% in both study years, and no major impacts were observed related to resource retirements. In addition, the 2018 ProbA Base Case results for 2022 were the same for the 2020 Base Case results (i.e., zero loss of load).

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	27.6%	26.8%
Reference	15.8%	15.8%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.00**	**0.00**
EUE (ppm)	**0.00**	**0.00**
LOLH (hours/year)	**0.00**	**0.00**

Risk Scenario Results

The results of the risk scenario showed an increase of potential loss of load, reflecting a slight increase in summer forced outages paired with a low-output wind year across the summer peak periods. Scenario analysis results show that LOLH and EUE values increase for 2024 when compared to the Base Case results. The modeling of the lowest wind output year paired with all load years showed the most impact in contributing approximately 80% to the increase of EUE and LOLH. Over 99% of the EUE and LOLH events occurred during the summer season. All risk was identified on peak load hours.

Scenario Case Summary of Results

	2022	2024
EUE (MWh)	--	**72.6**
EUE (ppm)	--	**2.44**
LOLH (hours/year)	--	**0.113**

Chapter 5: NPCC

Northeast Power Coordinating Council (NPCC) has five assessment areas, and the following pages contain the results for each. For each of the risk scenario result sections, a link to a more detailed report covering the modeling assumptions and results can be found in **Appendix E**. Note that the estimated metrics are consistent with NPCC's resource adequacy design criteria.[18]

> **Key Assessment Takeaway**
>
> NPCC's assessment areas generally pursued removing Tier 1 resources as their risk scenario with the exception of Ontario's choice to study nuclear refurbishment project delays. The assessment demonstrated that, with the removal of Tier 1 resources and transmission projects, the NPCC area reliability indices did not notably increase from the Base Case for all assessment areas, including Ontario. In general, the scenario results also emphasized the risks shown in the Base Case analysis and are consistent with other resource adequacy analysis.

NPCC-Maritimes

The Maritimes assessment area is a winter peaking NPCC subregion with a single Reliability Coordinator and two Balancing Authority areas. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to New Brunswick. The area covers 58,000 square miles with a population of 1.9 million. There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual subareas.

Risk Scenario Description

Tier 1 resources[19] were removed in other NPCC areas. The low levels of Tier 1 resources in the Maritimes area would not be an adequate test for severe conditions. For this reason, the area assumed the winter wind capacity is derated by half (1,224 MW to 612 MW) for every hour in December, January, and February to simulate widespread icing conditions and that only 50% (from 532 MW to 266 MW) of natural gas capacity is available due to winter curtailments of natural gas supplies. Dual fuel units are assumed to revert to oil.

The area has a diverse resource mix, and this scenario tests the reliability impacts associated with the most likely and therefore realistic shortages. Other scenarios did not meet the degree of severity and likelihood. This scenario was chosen to allow a direct comparison between the NERC and NPCC probabilistic analyses as the same severe scenario was used for both.

The results of this risk scenario are valuable to resource planners since they demonstrate a high level of reliability by meeting the NPCC LOLE target of not more than 0.1 days per year of exposure to load loss despite the severity of the scenario. Note that the required maximum LOLE for loss of load due to resource deficiencies is less than 0.1 days per year. Hence, since the LOLH value for both the Base Case and risk scenarios are less than this value, the NPCC target is met for both study years.

Base Case Results

The Base Case reserve margin for 2022 was 21%, slightly higher than the area's target of 20%. In the short term, unexpected delays in the development of advanced metering infrastructure in New Brunswick that led to conservative short-term increases in load forecasts, on peak sales of firm capacity to neighboring jurisdictions, and

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[18] i.e., they are calculated following all possible allowable "load relief from available operating procedures". For more information see Directory #1 (npcc.org)

[19] The term "Tier"" is used to describe categories of resources. This document is to be read alongside the NERC Long-Term Reliability Assessment that defines these categories.

retirement of small thermal generators in Prince Edward Island and the northern portion of Maine has reduced the Base Case planning reserve margins to levels slightly below the target levels of 20% in 2024, respectively.

For the two studied years, the halving of the Maritimes' wind resource capacity gave rise to non-zero values of EUE and LOLH with pronounced weighting during the months of December, January, and February; however, the values are low (on the order of single digits or fractions of MWh and hours). The results for 2022 are 0.575 MWh and 0.010 hours, respectively. The results are slightly worse for 2024 at 1.125 MWh and 0.023 hours, respectively. Expressed in terms of parts per million MWh of net energy for load, the EUE values are 0.021 and 0.039 for the years 2022 and 2024, respectively.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	19.3%	20.9%
Reference	20.0%	20.0%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.575**	**1.125**
EUE (ppm)	**0.021**	**0.039**
LOLH (hours/year)	**0.010**	**0.023**

Risk Scenario Results
As expected, with the additional loss of half of the area's wind and natural gas resources over and above the normal probability for loss of system resources, the risk scenarios reduce both the planning reserve margins to levels below the area's target of 20%. Forecast ranges for planning reserves are 17% and 15% for the two study years of 2022 and 2024, respectively.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**4.161**	**6.718**
EUE (ppm)	**0.149**	**0.236**
LOLH (hours/year)	**0.077**	**0.113**

For the two studied years, halving of the Maritimes' wind resource capacity gave rise to non-zero values of EUE and LOLH again with pronounced weighting during the months of December, January, and February and again the values are still low (being on the order of single digits or fractions of MWh and hours). The results for 2022 are 4.161 MWh and 0.077 hours, respectively. The results are slightly worse for 2024 at 6.718 MWh and 0.128 hours, respectively. Expressed in terms of parts per million MWh of net energy for load, the EUE values are 0.149 and 0.236 for the years 2022 and 2024.

NPCC-New England
ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It 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 BPS serves approximately 14.5 million people over 68,000 square miles.

Risk Scenario Description
Currently, in the probabilistic reliability analysis, the seasonal capacity ratings of the wind and solar resources are represented by a single value that is applicable to every hour of the day. The single value of the seasonal rating is based on the resource's seasonal claimed capability that are established by using its historical median net real power output during the reliability hours (hours ending 14:00–18:00 for the summer period, and 18:00–19:00 for the winter period). As the system evolves with higher behind-the-meter solar penetration, the daily peaks may occur in the hours outside of the established reliability-hours window. The reduction in the wind and solar resource's rating is meant to identify the impact on system reliability if the current rating methodology overstates the capacity value of these resources in the future with the peaks occurring in different hours. The removal of the Tier 1 future resources

is to take a conservative approach and identify the reliability consequences to the New England system if the in-service of these future resources is delayed.

Base Case Results

For year 2022, the 2018 study estimated an annual LOLH of 0.007 hours/year and a corresponding EUE of 2.713 MWh. In this year's study, the LOLH and the EUE slightly increased to 0.008 hours/year, and 3.292 MWh, respectively.

For year 2024, results show that the LOLH and the EUE values will increase to 0.095 hours/year, and a corresponding EUE of 58.618 MWh. The increase in LOLH and EUE is mainly attributed to the expected retirement of Mystic Units 8 and 9 (~1,400 MW) in the Boston area.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**29.4**	**18.95**
Reference	**13.9**	**12.7**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**3.292**	**58.62**
EUE (ppm)	**0.027**	**0.471**
LOLH (hours/year)	**0.007**	**0.095**

Risk Scenario Results

As expected, assuming less capacity contribution from the wind and solar resources and the delay of Tier 1 new resources will increase the LOLH and the EUE of the system. The LOLH and the EUE values are estimated to increase to 0.011 hours/year, and 5.3 MWh for 2022 (respectively) and to 0.135 hours/year and 88.1 MWh for 2024 (respectively). Expressed in terms of parts per million MWh of net energy for load, the EUE values are 0.038 and 0.625 for the years 2022 and 2024.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**5.3**	**88.1**
EUE (ppm)	**0.038**	**0.625**
LOLH (hours/year)	**0.011**	**0.135**

NPCC-New York

The New York ISO (NYISO) is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The transmission grid of New York State encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.5 million people. This represents approximately 37,317 MW[20] of existing-certain resources and net firm transfers anticipated for 2021. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Risk Scenario Description

This scenario evaluates the reliability of the system under the assumption that no major Tier 1 generation (see **Table 5.1**) or transmission (see **Table 5.2**) projects come to fruition within the ProbA study period. Below is a list of the major Tier 1 proposed transmission and generation projects that were removed from the Base Case.

Table 5.1: Tier 1 Generation Projects for NPCC-New York			
Unit Name	**Nameplate [MW]**	**Zone**	**2020 RNA COD**
Ball Hill Wind	100	A	12/2022
Baron Winds	238.4	C	12/2021
Cassadaga Wind	126.5	A	12/2021
Eight Point Wind Energy Center	101.8	B	12/2021
Calverton Solar Energy Center	22.9	K	12/2021
Roaring Brook Wind	79.7	E	12/2021

[20] NERC_LTRA_2020.pdf

Table 5.2: Tier 1 Transmission Projects for NPCC-New York						
Queue #	**Project Name**	**Zone**	**CRIS Request**	**SP MW**	**Interconnection Status**	**2020 RNA COD (In-Service Date)**
Proposed Transmission Additions, other than Local Transmission Owner Plans (LTPs)						
Q545A	Empire State Line	Regulated Transmission Solutions	N/A	N/A	Completed TIP Facility Study (Western NY PPTPP)	May 2022
556	Segment A Double Circuit				TIP Facility Study in progress (AC PPTPP)	December 2023
543	Segment B Knickerbocker-Pleasant Valley 345 kV				TIP Facility Study in progress (AC PPTPP)	December 2023
SDU	Leeds-Hurley SDU	System Deliverability Upgrades (SDU)	N/A	N/A	SDU triggered for construction in CY11	Summer 2021
CRIS Request						
430	Cedar Rapids Transmission Upgrade	D	80	80	CY17	October 2021

This scenario provides an indication of the potential reliability risks related to projects relied upon in the NYISO's 2020–2021 reliability planning process not materializing.

Base Case Results

The MARS planning model was developed by NPCC with input from each area (Ontario, New York, New England, Quebec, and Maritimes). The New York LOLH for 2022 and 2024 are 0.003 and 0.029 (hours/year), respectively, with corresponding EUE values of 0.594 and 6.837 (MWh), respectively. These values trend higher than the past ProbA results. The trend is mainly due to the decrease in the forecasted Prospective Reserve Margin and Operable Reserve Margins.[21] The New York area is summer-peaking and the LOLH and EUE risk occurs primarily during the summer months.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	19.8%	18.6%
Reference	15.0%	15.0%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.594**	**6.837**
EUE (ppm)	**0.004**	**0.046**
LOLH (hours/year)	**0.003**	**0.029**

Risk Scenario Results

As expected, if no major Tier 1 transmission and generation projects are assumed to come in-service within ProbA study period, the LOLH and EUE results are observed to be higher than ProbA Base Case. The LOLH for 2022 and 2024 are 0.003 and 0.045 (hours/year), respectively, with corresponding EUE values of 0.681 and 13.904 (MWh). Expressed in terms of parts per million MWh of net energy for load, the EUE values are 0.005 and 0.093 for the years 2022 and 2024.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**0.681**	**13.904**
EUE (ppm)	**0.005**	**0.093**
LOLH (hours/year)	**0.003**	**0.045**

[21] As defined by NERC for the Long-Term Reliability Assessments and ProbA application.

NPCC-Ontario

The Ontario Independent Electricity System Operator is the Planning Coordinator, Resource Planner, and Balancing Authority for Ontario as defined by NERC. As detailed in Section 8 of the [Ontario Resource and Transmission Assessment Criteria](), the IESO follows the Northeast Power Coordinating Council resource adequacy criterion. ORTAC Section 8.2 states that the IESO will not consider emergency operating procedures for long-term capacity planning. The IESO also currently does not consider assistance over interconnections with neighboring Planning Coordinator areas as contributing to resource adequacy needs in the annual planning outlook resource adequacy assessments.

Risk Scenario Description

Ontario currently has 18 nuclear units, 6 of which are expected to retire by 2024/2025. As of today, one unit has been refurbished with nine more units being refurbished over the next decade. Given the size of each nuclear unit, there is a significant risk to resource adequacy if the return of any unit is delayed due to unforeseen circumstances. For this reason, the IESO chose refurbishment project delays for their risk scenario. Additionally, the demand forecast was increased by 5% for Ontario risk scenario to reflect possible rapid economic recovery from COVID-19 impacts.

Removing Tier 1 resources would not have been an appropriate scenario to test the system because those resources amounted to only 360 MW.

Base Case Results

The previous ProbA estimated an annual LOLH of 0.0 hours/year and EUE of 0.0 MWh for the year 2022. The median peak demand forecast for 2022 has increased by 2.5% compared to the 2018 forecast. The current forecasts are LOLH of 0.0 hours/year and EUE of 0.049 MWh for the year 2022. No difference in the estimated LOLH and a marginal difference in EUE are observed between the two assessments.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	20.1%	11.3%
Reference	23.8%	16.8%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.000**	**0.049**
EUE (ppm)	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**

Risk Scenario Results

The ProbA risk scenario estimated an annual LOLH of 0.0013 hours/year and EUE of 0.0925 MWh for the year 2022. For the year 2024, the estimated annual LOLH was 0.171 hours/year and EUE was 99.7 MWh as expected. Expressed in terms of parts per million MWh of net energy for load, the EUE values are 0.000 and 0.692 for the years 2022 and 2024.

The results emphasize the resource adequacy needs that Ontario faces in the mid to long-term. The IESO is transitioning to the use of competitive mechanisms with stakeholder inputs to meet Ontario’s adequacy needs.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**0.0925**	**99.7**
EUE (ppm)	**0.000**	**0.692**
LOLH (hours/year)	**0.0013**	**0.171**

NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8.5 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.

Risk Scenario Description

In this scenario, it is assumed that Tier 1 resources be removed to test the reliability impacts associated with the most likely and therefore realistic shortages. Other scenarios are less likely compared to this scenario.

Base Case Results

The Base Case reserve margin for 2022 was 13.2%, higher than the area's reference reserve margin of 10%.

In the short term, increase in load forecasts, on peak sales of firm capacity to neighboring jurisdictions reduced the Base Case planning reserve margins to levels slightly below the reference reserve margin of 10% in 2024.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	13.5%	14.0%
Reference	10.1%	10.1%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.00**	**0.000**
EUE (ppm)	**0.00**	**0.000**
LOLH (hours/year)	**0.00**	**0.000**

For the two studied years, the results are zero for EUE and LOLH. Expressed in terms of parts per million MWh of net energy for load, the EUE values are zero for the years 2022 and 2024.

Risk Scenario Results

As expected, after removing all Tier 1 resources, the risk scenarios reduce both the planning reserve margins to levels below the area's target of 10%. Forecast ranges for planning reserves are 13.0% and 8.9% for the two study years of 2022 and 2024, respectively. For the two studied years, the EUE and LOLH remain close to zero.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**0.00**	**0.000**
EUE (ppm)	**0.00**	**0.000**
LOLH (hours/year)	**0.00**	**0.000**

Chapter 6: RF-PJM

PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. It is part of the Eastern Interconnection and serves approximately 65 million people over 369,000 square miles.

Key Assessment Takeaway

PJM decided to remove all Tier 1 resources as part of their scenario. They demonstrate no significant rise in reliability indices as a result of these removals.

Risk Scenario Description

The risk scenario considers the removal of all Tier 1 units[22] from the simulation. This scenario serves as a proxy for potential withdrawals or delays of queue projects in the PJM interconnection queue. PJM chose this scenario due to the delay in the reliability pricing model's (RPM) schedule (resulting from the minimum offer price rules proceedings at FERC); RPM provides entry price signals for planned resources, such as those labeled as Tier 1 resources. Furthermore, the risk scenario provides resource adequacy planners with an opportunity to analyze the impact of a higher RTO-wide forced outage rate on reliability metrics due to the fact that, in general, Tier 1 units are expected to have lower forced outage rates than existing units. This is because most Tier 1 units are combined cycle units. This scenario provides value to resource adequacy planners due to the fact that it considers reserve margins that are much lower than current reserve margins at PJM.

Base Case Results

The Base Case results in LOLH and EUE equal to zero for both 2022 and 2024 due to large Forecast Planning Reserve Margins (36.6% and 40.1%, respectively). These reserve margins are significantly above the reference values of 14.5% and 14.4%, respectively. Note that these large Forecast Planning Reserve Margin values include Tier 1 resources (~15,000 MW in 2022 and ~23,000 MW in 2024). Historically, a significant share of Tier 1 resources, 20–30%, drop out of the Interconnection queue process.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**33.5%**	**36.6%**	**40.1%**
Reference	**15.8%**	**14.5%**	**14.4%**
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.000**	**0.000**	**0.000**
EUE (ppm)	**0.000**	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**	**0.000**
2022*: results from the 2018 ProbA			

The LOLH and EUE in the 2020 study are identical to the values reported in the 2018 study. There are no differences in the EUE and LOLH results because in both studies the Forecast Planning Reserve Margin values are well above the reference values. Furthermore, the Forecast Planning Reserve Margin for 2022 in the 2020 study has actually increased compared to the value in the 2018 study due to a slightly higher amount (~300 MW) of forecast capacity resources and a lower (~3,000 MW) net internal demand value.

[22] "Tier 1" resources refers to planned resources in the PJM Interconnection Queue with an executed Interconnection Service Agreement (or its equivalent). See footnote 15 for more reference to the term "Tier"

Risk Scenario Results

The regional risk scenario yields LOLH and EUE values that are practically zero for both 2022 and 2024 (the EUE value of 0.33 MWh in 2024 is, for all intents and purposes, a negligible value).

These results are also caused by Forecast Planning Reserve Margins, even after excluding Tier 1 resources, which are well above the reference values (i.e., 25.9% vs. a reference value of 14.5% in 2022 and 24.1% vs. a reference value of 14.4% in 2024).

Risk Scenario Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**25.9%**	**24.1%**
Reference	**14.5%**	**14.4%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.000**	**0.330**
EUE (ppm)	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**

Note that PJM's anticipated reserve margins in the Base Case and the risk scenario are largely driven by past and expected outcomes of PJM's capacity market, the Reliability Pricing Model. By design, this model allows for the possibility of procuring reserve margin levels above the reference levels.[23]

[23] Sections 3.1–3.4 in PJM Manual 18 available at https://www.pjm.com/~/media/documents/manuals/m18.ashx

Chapter 7: SERC

SERC covers approximately 308,900 square miles and serves a population estimated at 39.4 million. The RE includes four NERC assessment areas: SERC-East, SERC-Central, SERC-Southeast, and SERC-Florida Peninsula.

In addition to seeing loss of load risk during peak load summer months, SERC is also experiencing tighter operating conditions during non-summer months. One factor that has contributed to this trend is the amount of thermal generation resources taking planned maintenance outages during the shoulder months. While the LTRA projects reserves for summer, winter, and annual assessments, it may not highlight risk, if any, during spring and fall.

> **Key Assessment Takeaway**
>
> SERC's increase of maintenance outages on their Base Case did not demonstrate a significant increase of Reliability Indices. In response, SERC then altered their cases to ensure each of the regions started at a LOLE of 0.1. This change allowed SERC to determine that their Reliability Indices produce an exponential relationship to the increase of maximum capacity undergoing maintenance. This is able to be mitigated by proper coordination of planned outages.

SERC has not experienced any reliability events directly related to planned maintenance outages. However, reports on events in neighboring REs highlight the importance of evaluating this risk for SERC. A FERC and NERC staff report on the 2018 cold weather event[24] identified that planned outages contributed to system reliability risk in the South-Central United States. Additionally, MISO declared maximum generation events in January and May of 2019 that support MISO's finding that the combination of high planned outages, reduced capacity availability, and volatile load has increased the risk of capacity shortages during non-summer months.[25]

Risk Scenario Description

To investigate the impact of planned maintenance outages on system risk, SERC conducted a sensitivity study in the 2020 ProbA that increased the amount of planned maintenance outages on the SERC system for year 2024. This sensitivity study helps resource adequacy planners understand how planned maintenance outages can impact the distribution of loss of load risk across all times of the year and improves the ability to plan maintenance outage schedules that minimize loss of load risk.

SERC incrementally increased the planned maintenance rates for thermal resources to test the reliability of the SERC system under a scenario with higher levels of planned maintenance outages. Given that the Base Case metrics are very small for many of SERC's subregional areas, known as metric reporting areas (MRAs), SERC performed a two-part sensitivity study. One starting with the base report and the other starting at each MRA's PRM resource level) where the starting point reserves were adjusted for each MRA to reach the LOLE target of 0.1 days/year. In both parts of the sensitivity study, the Base Case planned outage rates were multiplied by factors of 1.5, 2.0 and 2.5.

Base Case Results

The 2020 ProbA Base Case results show that each of the MRAs are projected to have reserves and access to imports from neighboring areas that are well more than that needed to meet the 0.1 days/year LOLE target. In the 2020 study year, the planning reserve margins (PRM) results are 21.8% for 2022 and 18.9% for 2024. These projections are higher than the SERC 2018 ProbA study. The increase in PRM could be attributed to several modeling changes in the 2020 study, particularly the integration of Florida Peninsula, a rapidly changing capacity mix, and updates to transfer capacities. The snippets of the 2020 LTRA tables for the Base Case results for all SERC MRAs are found below.

[24] FERC and NERC Release Report on January 2018 Extreme Cold Weather Event

[25] Resource Availability and Need, Evaluation Whitepaper September 2018 and MISO January 2019 Max Gen Event Overview and May 2019 Max Gen Event Overview

SERC-Central: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**24.9%**	**26.4%**	**27.0%**
Reference	**14.4%**	**15.0%**	**15.0%**
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.000**	**0.001**	**0.001**
EUE (ppm)	**0.000**	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**	**0.000**

SERC-East: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**24.9%**	**22.8%**	**23.9%**
Reference	**14.4%**	**15.0%**	**15.0%**
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.000**	**0.717**	**5.262**
EUE (ppm)	**0.000**	**0.003**	**0.024**
LOLH (hours/year)	**0.000**	**0.001**	**0.009**

SERC- Southeast: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**32.4%**	**35.8%**	**39.1%**
Reference	**14.4%**	**15.0%**	**15.0%**
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.00**	**0.009**	**0.028**
EUE (ppm)	**0.00**	**0.000**	**0.000**
LOLH (hours/year)	**0.00**	**0.000**	**0.000**

SERC-Florida Peninsula: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**N/A**	**21.6%**	**22.8%**
Reference	**N/A**	**15.0%**	**15.0%**
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**N/A**	**22.66**	**2.262**
EUE (ppm)	**N/A**	**0.096**	**0.009**
LOLH (hours/year)	**N/A**	**0.035**	**0.004**

An asterisk (*) denotes results from the 2018 ProbA

Risk Scenario Results

When using the maintenance multiplier of 1x, maintenance outages are primarily scheduled March–May and September–November for SERC-C, SERC-SE, and SERC-E. In SERC-FP, maintenance outages are scheduled throughout the year, except for summer. Increasing the multiplier beyond 1.5x causes maintenance outages to begin to be scheduled in the peak load summer months. **Figure 7.1** shows how the multipliers impact the maximum capacity undergoing maintenance during the simulation.

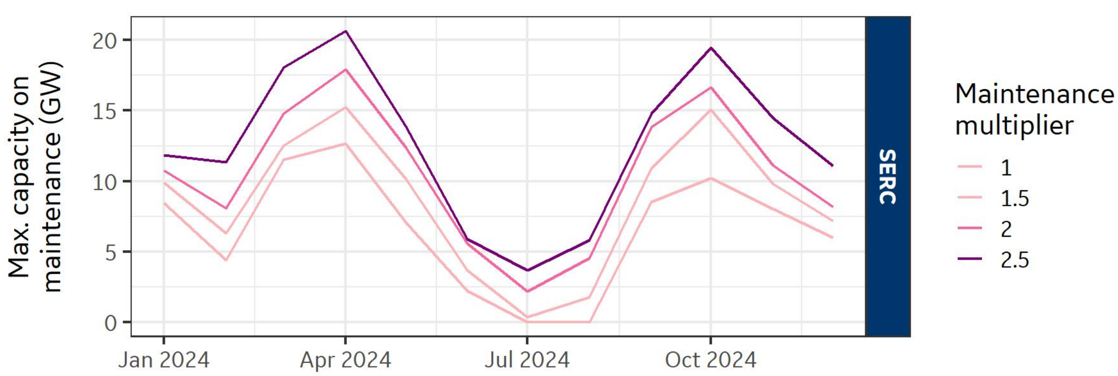

Figure 7.1: Maximum Simultaneous Capacity on Maintenance Outage for all of SERC

The reliability metrics for the Base Case are summarized in **Table 7.1**. The MRAs that had a measurable amount of LOLE in the Base Case (SERC-E and SERC-FP) see an increase in their observed metrics as the maintenance multiplier is increased; however, this increase in LOLE is somewhat moderate. For instance, in the case with double the maintenance rates, both SERC-E and SERC-FP have a LOLE below 0.1 days/year.

Table 7.1: Reliability Indices for Increased Maintenance for Base Case, Year 2024

MRA	Maintenance Multiplier	LOLE (days/yr)	LOLH (hrs/yr)	EUE (MWh/yr)	EUE (MPM)
SERC-C	1.0	0.000	0.000	0.0	0.000
	1.5	0.000	0.000	0.0	0.000
	2.0	0.001	0.002	1.1	0.005
	2.5	0.008	0.017	12.2	0.055
SERC-SE	1.0	0.000	0.000	0.0	0.000
	1.5	0.000	0.000	0.0	0.000
	2.0	0.001	0.001	0.4	0.002
	2.5	0.008	0.013	7.5	0.030
SERC-E	1.0	0.004	0.009	5.3	0.024
	1.5	0.012	0.019	12.3	0.056
	2.0	0.085	0.136	107.8	0.490
	2.5	0.277	0.574	517.4	2.349
SERC-FP	1.0	0.003	0.004	2.3	0.009
	1.5	0.018	0.024	19.1	0.079
	2.0	0.099	0.147	141.4	0.583
	2.5	0.320	0.518	513.3	2.114
SERC	1.0	0.006	0.013	7.6	0.006
	1.5	0.029	0.043	31.5	0.023
	2.0	0.183	0.284	250.8	0.186
	2.5	0.588	1.087	1,050.4	0.778

Given that the Base Case metrics are very small for many of the MRAs, SERC performed a second set of simulations to better understand the impact of higher maintenance outages in all MRAs. Instead of starting with the Base Case scenario, the starting point was the final step in the ProbA's interconnected PRM simulation, where every MRA in the model experiences a LOLE of 0.1 days/year. This provides a starting point with observable loss of load statistics for all the areas. **Table 7.2** show that all the MRAs experience an exponential increase of LOLE and other metrics as the maintenance multiplier increases in the PRM case. The increase is similar across all MRAs with the exception that SERC-FP experiences a larger-than-average increase in LOLE. **Figure 7.2** also highlights this same exponential increases under this second simulation.

Table 7.2: Reliability Indices for Increased Maintenance for Planning Reserve Margin Case, Year 2024					
MRA	**Maintenance Multiplier**	**LOLE (days/yr)**	**LOLH (hrs/yr)**	**EUE (MWh/yr)**	**EUE (MPM)**
SERC-C	1.0	0.100	0.263	255.8	1.166
	1.5	0.156	0.379	402.4	1.835
	2.0	0.594	1.517	2,139.7	9.757
	2.5	1.772	4.863	6,560.1	29.916
SERC-SE	1.0	0.099	0.233	280.9	1.113
	1.5	0.136	0.296	349.6	1.386
	2.0	0.521	1.131	1,418.4	5.623
	2.5	1.800	4.442	6,079.4	24,098
SERC-E	1.0	0.100	0.256	275.5	1.251
	1.5	0.142	0.331	343.8	1.561
	2.0	0.554	1.204	1,208.4	5.486
	2.5	1.799	4.634	5,218.9	23.691
SERC-FP	1.0	0.100	0.203	160.0	0.659
	1.5	0.261	0.440	394.7	1.626
	2.0	0.805	1.474	1,573.9	6.482
	2.5	2.321	4.810	5,484.6	22.588
SERC	1.0	0.307	0.767	1,527.0	1.131
	1.5	0.561	1.197	2,177.4	1.613
	2.0	1.908	4.485	8,815.7	6.532
	2.5	6.523	18.373	35,211.9	26.091

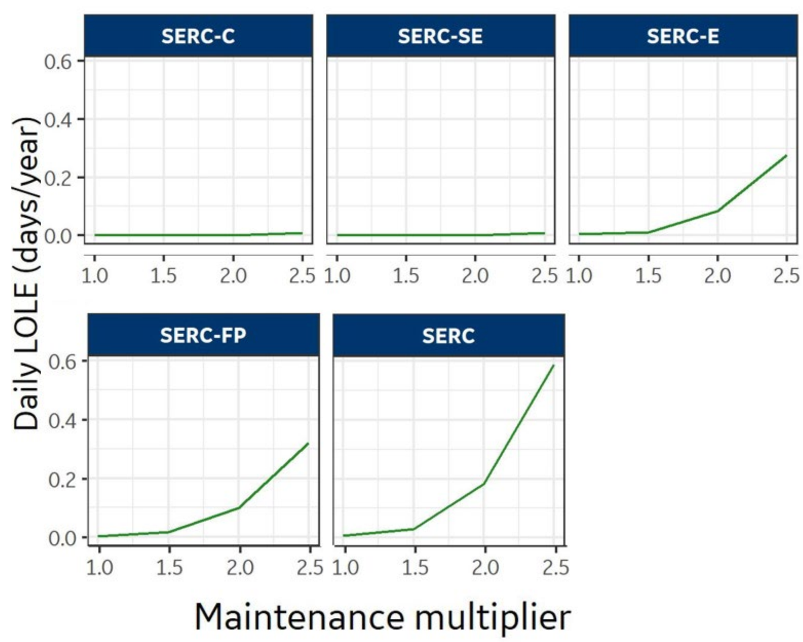

Figure 7.2: Loss of Load Statistics by Maintenance Multiplier per MRA

Figure 7.3 shows that under the 1x multiplier case, the majority of MRAs have the largest accumulation of LOLE in the summer. SERC-FP is the exception with nearly 20% of the LOLE occurring during the winter. As the maintenance multiplier increases, most MRAs experience less LOLE in the summer and more LOLE in the spring and fall. SERC-FP is again the exception with the majority of the LOLE moving to the winter and a smaller portion of LOLE moving to the fall.

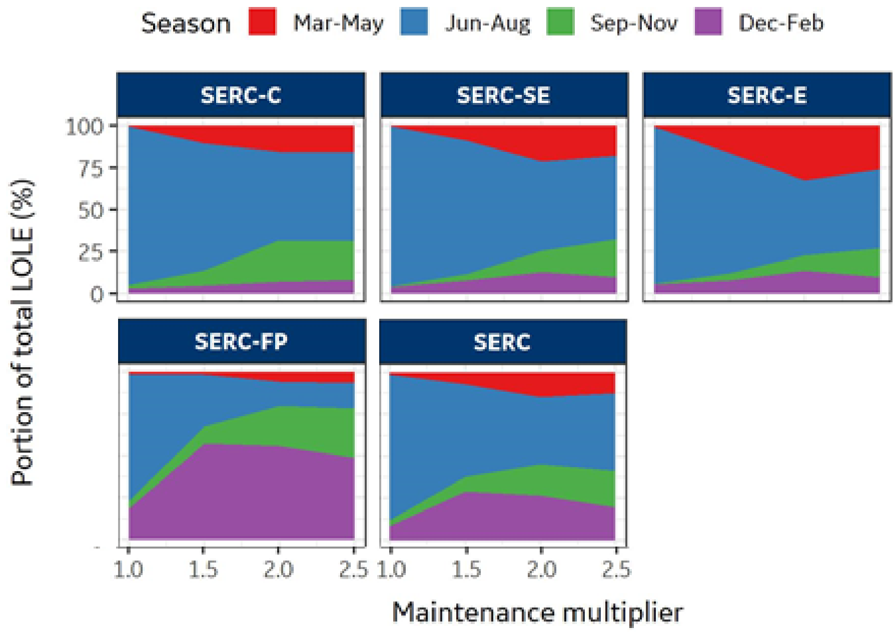

Figure 7.3 Seasonal LOLE Distribution for PRM Cases with Increased Maintenance

Risk and Recommendations

The sensitivity scenarios indicate that the risk in year 2024 associated with increased planned maintenance outages is low to moderate. For instance, the MRAs with the highest increase in LOLE, SERC-E and SERC-FP were still below 0.1 LOLE with double the maintenance rates. The small increase in LOLE for the SERC MRAs resulting from increased planned maintenance outages can be partially attributable to the fact that the SERC MRAs in 2024 are projected to have reserves and access to imports from neighboring areas that are well in excess of what is needed to meet the 0.1 days/year LOLE target.

The results of this sensitivity study highlight the need for planned outage coordinators to develop unique maintenance schedules that align with expected local weather and system conditions. For this reason, the optimal time periods for scheduling maintenance outages vary across the SERC MRAs.

It is worth noting that the model assumes an optimized outage schedule based on foresight of average weather conditions. The GE MARS software schedules planned outages with a "packing" algorithm that schedules maintenance in the weeks with highest margins. A further comparison between the maintenance schedule developed by GE MARS and historical maintenance schedules could be insightful in understanding the findings of this sensitivity study. A redacted copy of the SERC 2020 ProbA report can be found in the SERC website by using the link in Appendix E.

Chapter 8: Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) area encompasses about 75% of the land area in Texas. The grid delivers approximately 90% of the electricity used by more than 26 million consumers in Texas.

Key Assessment Takeaway

ERCOT demonstrates that, by resampling their wind profiles with their load profile to emphasize low to moderate amounts of wind, has a significant effect on net load peaks and increases reliability indices. This increase is similar to degrading a system better LOLE to a LOLE of 1-day-in-10 years, which is a typical comparison in industry. This indicates that the ERCOT system increases in Reliability Indices for their scenario, while significant in comparisons to the Base Case, are not significant in comparison to industry accepted standards.

Risk Scenario Description

The total installed wind capacity in ERCOT is around 25 GW, and an additional 13 GW of new wind is expected to come on-line in the next three to four years. Furthermore, the two energy emergency alert events in the 2019 summer were primarily due to low output from wind resources. In addition, simulated loss of load events in ERCOT are largely driven by high load combined with low wind output conditions. These conditions occur with relative rarity such that a relatively small change in their frequency could have significant impact on the expected reliability of the ERCOT system. The risk scenario for ERCOT was designed to stress test the impact of a difference in the realized frequency of high load and low wind events from that in the synthetic profiles used for the Base Case simulations. Other aspects of the study can be found in **Appendix B**.

To construct the alternate wind profiles that reflect a higher likelihood of low wind output, a filter was performed for days in the simulated Base Case which had any firm loss of load. An alternate wind profile for each day was randomly selected from the wind profiles from this set of days. This re-shuffling of load and wind profiles was performed 100 times. The sampled sets of profiles that represent the most extreme and tenth most extreme sets of net load profiles were selected to be simulated for 2024. The criteria for most extreme was based on the set with the highest average net loads in the top 40 net load days.

Base Case Results

The Base Case study indicates few reliability events. As compared to the 2018 ProbA study, the reserve margin has increased substantially primarily due to an increase in solar resources. More than 12 GW of additional solar installed capacity is expected in 2022 now than was forecast when the 2018 ProbA study was published. Compared to the results from the 2018 ProbA Study, LOLH decreased from 0.87 to 0.00 for the first study year. The results are driven by an increase in the Anticipated Reserve Margin that resulted from growth in planned solar and wind capacity.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**19.1%**	**15.5%**
Reference	**13.8%**	**13.8%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**.05**	**12.86**
EUE (ppm)	**0.00**	**0.03**
LOLH (hours/year)	**0.00**	**0.01**

Risk Scenario Results

Resampling the wind profiles on peak load days increased the average net load peak for the top 40 net load days by 235 MW for the tenth most extreme scenario and 525 MW for the most extreme scenario. A snapshot of the top 40 daily net load peaks for each of the scenarios is shown below in **Figure 8.1**. In the most extreme days in the risk scenarios, the daily net load peak is over 1,000 MW higher than in the Base Case.

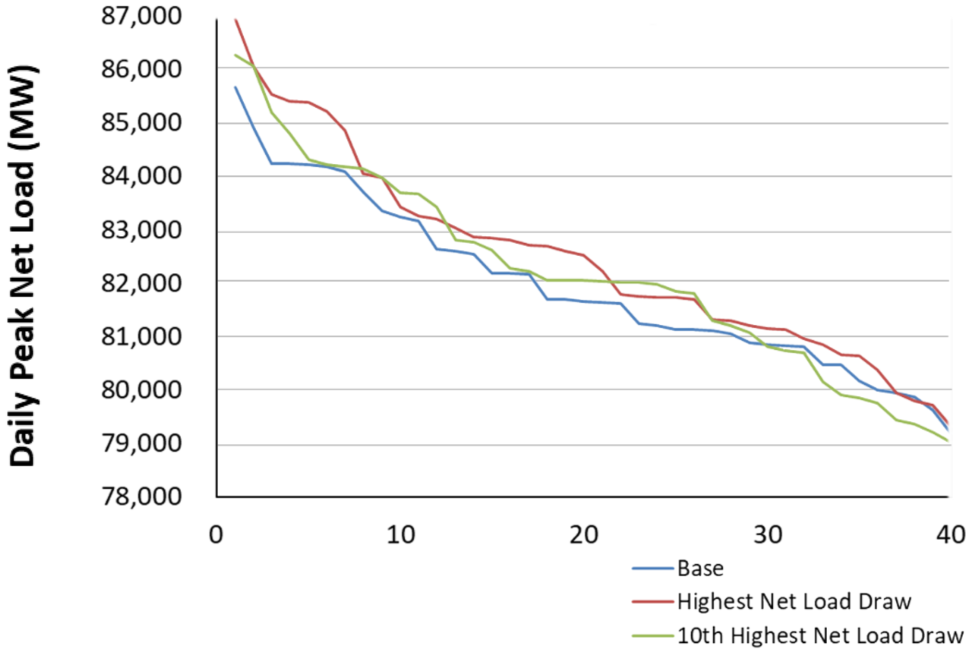

Figure 8.1: ERCOT's Load profiles for Various Assumptions

The increase in net load corresponds to a degradation of reliability when the risk scenarios are simulated. While the assumption that daily wind profiles from peak load days are fungible is not realistic, it likely provides an upper bound for the impact of wind profile uncertainty on average reliability metrics. The scenario results are compared to those found in the Base Case in **Table 8.1** and highlight this upper boundary.

Table 8.1: Scenario Case Reliability Index Comparison

Reliability Index	Base Case	10th Highest Net Load Draw	Highest Net Load Draw
EUE [MWh]	12.86	31.0	64.72
LOLH [hrs/yr]	0.01	0.03	0.05

Since reliability metrics in the Base Case are quite low, the risk scenario impact appears quite large. EUE and LOLH in the highest net load draw scenario increase by a factor of approximately five. However, simulating the risk scenarios at a lower reserve margin that is more consistent with industry standard reliability expectations (0.1 LOLE) suggests a smaller impact. In this case, LOLH increases from .24 to .49 for the highest net load draw scenario.

Chapter 9: WECC

The Western Interconnection serves over 80 million people. The interconnection spans 1.8 million square miles in all or part of 14 states, the Canadian provinces of British Columbia and Alberta, and the northern part of Baja California in Mexico. Due to unique geography, demographics, and history, the Western Interconnection is distinct in many ways from the other North American interconnections.

Key Assessment Takeaway

WECC, like NPCC, performs a simulation for multiple different assessment areas. These areas all were subject to a reduction of coal-fired generation and demonstrated varying results. In some areas, this scenario greatly impacted their reliability indices and in others, no significant increase was observed from the Base Case results. WECC determined that the impact of a reduction of coal-fired generation on the reliability Indices depends heavily on the current penetration of coal-fired generation in the assessment area, as well as the assessment area's ability to take on external assistance under higher demand. Such a result is not indicative for more or less coal, but that the impact of faster retirements than expected has a varying impact on the reliability indices in each assessment area.

Risk Scenario Description

The Western Electricity Coordinating Council (WECC) Regional Risk Scenario examines the impacts to resource adequacy associated with potential coal-fired generation retirements. The generation resources included in this scenario started with the LTRA resources and removed additional coal-fired generation resources that are expected to retire but do not yet have an approved decommission plan.

Coal-fired generation is a key baseload component of the Western Interconnection's resource mix but is also one of the most controversial. With the retirement or planned retirement of considerable amounts of coal-fired generation, and an increase in variable energy resources, the need to ensure sufficient capacity to reliably meet electricity demand at any given hour within the Western Interconnection is becoming more significant. This scenario specifically analyzes the reliability impacts of retiring coal plants beyond those that are being retired in the LTRA; this assessment includes coal retirements that are based on the best information provided by stakeholders or are mandated by state polices. This scenario also provides insights into where additional risk may occur with fewer baseload resources and examines the effects of these potential retirements to help mitigate reliability risks to the BPS.

WECC's reliability risk priorities focus on four reliability concerns: Resource Adequacy and Performance, Changing Resource Mix, Distribution System and Customer Load Impacts on the BPS, and Extreme Natural Events. It would be appropriate to study any of these topics, but resource adequacy incorporates elements of each priority and serves as the basis for additional studies in each of these priorities. If more information is desired, see **Appendix E** for the link to WECC's *Western Assessment of Resource Adequacy Report*, which contains more details.

Coal-fired generation has historically been a major energy resource in the Western Interconnection. However, as the generation resource mix in the Western Interconnection transitions from thermal based resources to variable generation resources, coal-fired generation will continue to be retired. This study examines the impacts on resource adequacy and planning reserve margins associated with aggressive coal-fired generation retirements.

It is anticipated that coal-fired generation retirements will continue both in response to governmental directives and for economic reasons. For the most part, these baseload resources are being replaced by variable generation, such as wind and solar. Resource adequacy planners need to understand the variability associated with wind and solar generation and incorporate probabilistic studies in the resource adequacy planning process. This assessment is focused on examining the risks to resource adequacy associated with not having enough resources to meet demand following aggressive coal-fired generation retirements.

Figure 9.1 shows the amount of possible coal retirements over the next ten years that were not reported in the LTRA or ProbA Base Case. The years 2022 and 2024 are highlighted as the years reported in the scenario. Accumulated coal-fired capacity retirements that were included in the ProbA scenario total over 2,300 MW.

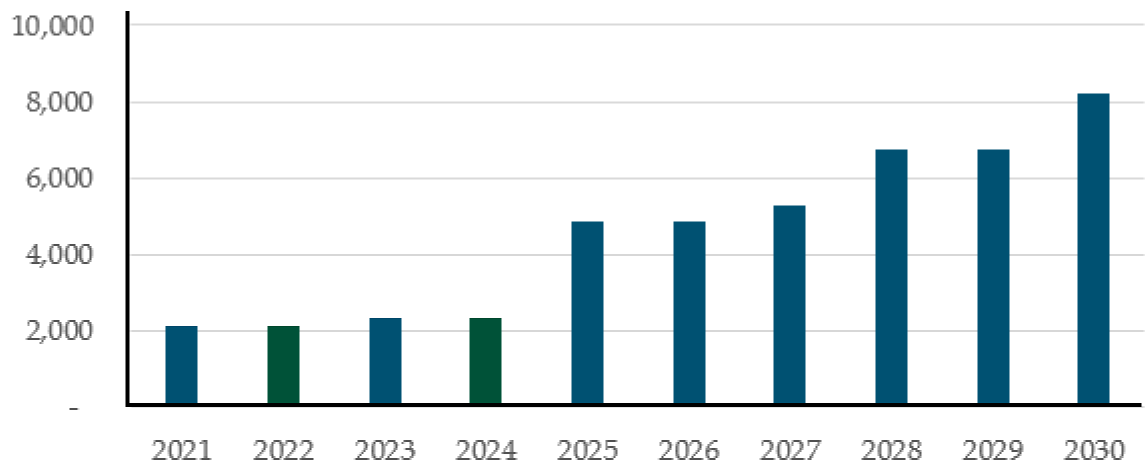

Figure 9.1: WECC's Possible Coal Retirement Capacity by Year[26]

WECC-California-Mexico (CAMX)

The CAMX subregion is a summer-peaking subregion that consists of most of the state of California and a portion of Baja California, Mexico. The CAMX subregion has two distinct peak periods, one in southern California and one in northern California, that benefit the subregion as there are resources available in one area when the other is experiencing their demand peak.

Demand

The CAMX subregion is expected to peak in late August at approximately 53,400 MW for both 2022 and 2024. Overall, the CAMX subregion should expect a 100% ramp, or 26,700 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 66,000 MW (equating to a 24% load forecast uncertainty) and high as 65,000 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 is 50,400 MW. Under low-resource availability conditions, the CAMX subregion may only have 44,300 MW to meet a 53,400 MW expected peak. The expected availability of resources on the peak hour in 2024 is 54,400 MW. Under low-resource availability conditions, the CAMX subregion may only have 46,400 MW to meet a 53,400 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 45,000 MW, the low availability end of the spectrum would only see a loss of 4,000 MW, or less than 10%. However, solar resources total 6,500 MW and could lose 5,500 MW, or nearly 90%, on a low-availability end of the spectrum for resource availability.

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[26] For further information regarding this study, use the link in Appendix E to access the WECC's Western Assessment of Resource Adequacy report.

For this scenario, there were no new coal retirements included in this subregion. However, coal retirements that occurred in the other subregions did have an impact in the amount of energy available to transfer to CAMX.

Planning Reserve Margin

Given the growing variability, a 15% margin for the CAMX area is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 40%, so it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 11,000 MW, or 20%, of the expected peak demand.

Risk Scenario Results

For CAMX, the reliability indices are summarized in **Table 9.1** and broken out by the CA area and the MX area. The Mexico portion of the CAMX area has seen a significant increase in their demand forecast since the 2018 ProbA was published. The annual energy demand forecast for 2022 was expected at around 15,900 GWh when reported for the 2018 ProbA. In the 2020 ProbA, the annual energy forecast has risen to approximately 16,900 GWh, a change of approximately 6.0%. This new demand forecast, coupled with the California portion of the area's inability to transfer energy after the peak hours in the evening due to their own shortfalls, has led to a significant increase in expected unserved energy for this region. Looking at the California portion of this area, the LOLH and EUE have improved since last ProbA with large improvements by 2024.

Table 9.1: Reliability Index Comparison-CAMX

Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
California Only						
EUE [MWh]	26,930	29,266	2,336	6,886	36,164	29,278
EUE [ppm]	146	159	13	27	133	106
LOLH [hrs/yr]	0.8	0.8	0	0.15	0.74	0.59
						Mexico Only
EUE [MWh]	987,786	1,392,212	416,426	2,396,090	2,991,820	595,730
EUE [ppm]	3,622	5,152	1,530	8,793	10,846	2,053
LOLH [hrs/yr]	21	31	10	55	70	15

Annual Demand at Risk (DAR)[27]

In 2022, for the scenario, the CAMX subregion could experience as many as 32 hours where the 1-day-in-10 years LOLE threshold of resource adequacy is not maintained and up to 71 hours by 2024. For the Base Case, the results were 22 and 56 hours, respectively. Given that the CAMX subregion will need to rely heavily on external assistance to maintain resource adequacy, the impacts on demand at risk resulting from the scenario came from retirements in other subregions as no coal was retired in CAMX.

Hours at Risk

A system-wide high demand scenario would eliminate much of the external assistance available for CAMX, causing the hours where simulated load exceeded available resources to be exacerbated, and a low-availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the CAMX subregion will likely have many hours where the 1-day-in-10 years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Energy at Risk

In 2022, about 5,200 per million MWh of energy[28] is at risk in the scenario case and grows to nearly 11,000 per million MWh by 2024. In the Base Case, the results were 3,700 and 8,800 per million MWh, respectively. For the 32 hours of

[27] WECC distinguishes the term LOLH as "Demand at Risk (DAR)." The two terms here are synonymous.

[28] Any reference to "per million MWh of energy" can be translated to a EUE in total MWh in the tables provided for each area.

potential demand at risk in the scenario results, this would equate to approximately 162 per million MWh on average in 2022. For the 71 hours of potential demand at risk in the scenario results, this would equate to approximately 155 per million MWh on average in 2024.

WECC-Southwest Reserve Sharing Group (SRSG)

The SRSG subregion is a summer-peaking area that consists of the entire states of Arizona and New Mexico and a portion of the states Texas and California.

Demand

The SRSG subregion is expected to peak in mid-July at approximately 26,100 MW in 2022 and 26,900 MW in 2024. Overall, the SRSG subregion should expect a 93% ramp, or 12,600 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 29,600 MW (equating to a 13% load forecast uncertainty) and as high as 30,600 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 is 29,600 MW. Under low-resource availability conditions, the SRSG subregion may only have 24,100 MW to meet a 26,100 MW expected peak. The expected availability of resources on the peak hour in 2024 is 29,200 MW. Under low-resource availability conditions, the SRSG subregion may only have 24,200 MW to meet a 26,900 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Although baseload resources account for roughly 25,000 MW of availability, the low availability end of the spectrum would only see a loss of 3,100 MW. However, solar resources total 1,400 MW but could expect to lose 600 MW, or nearly half, on a low availability end of the spectrum.

For this scenario, there were approximately 400 MW of additional coal retirements included in this subregion.

Planning Reserve Margin

Given the growing variability, a 16% margin for the SRSG subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 27%, so it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 3,500 MW (13%) of the expected peak demand. As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Risk Scenario Results

For the SRSG area, the reliability indices are summarized in **Table 9.2**.

Table 9.2: Reliability Index Comparison-SRSG

Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
EUE [MWh]	11	212	201	81	437	356
EUE [ppm]	0.106	2.05	1.90	0.75	4.03	3.28
LOLH [hrs/yr]	0.001	14.7	14.6	0.004	22	22

Annual Demand at Risk

In 2022 for the scenario, the SRSG subregion could experience as many as 14 hours where the 1-day-in-10 years LOLE threshold of resource adequacy is not maintained and up to 22 hours by 2024. For the Base Case, the results were less than an hour in both years. The impacts of the scenario came from the 400 MW coal retirement as well as impacts from external assistance in other subregions.

Hours at Risk

A system wide high-demand scenario would eliminate much of the external assistance available for SRSG, causing the hours where simulated load exceeded available resources to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the SRSG subregion is expected to have many hours where the 1-day-in-10 years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Energy at Risk

In 2022, about 2 per million MWh of energy is at risk in the scenario case and grows to nearly 4 per million MWh by 2024. In the Base Case, the results were less than 1 per million MWh for both years.

WECC-Northwest Power Pool-United States (NWPP-US)

The Northwest Power Pool U.S. subregion consists of the northern United States and central portions of the Western Interconnection. This subregion is both summer and winter peaking depending on location. The area covers all the states of Washington, Oregon, Idaho, Nevada, Utah, Colorado, and Wyoming as well as portions of the states of Montana, California, South Dakota, and Nebraska.

Demand

The NWPP-US subregion is expected to peak in late-July at approximately 65,000 MW in 2022 and 66,100 MW in 2024. Overall, the NWPP-US subregion should expect an 81% ramp, or 29,100 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 73,700 MW (equating to a 13% load forecast uncertainty) and as high as 75,500 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 and 2024 is 81,300 MW. Under low-resource availability conditions, the NWPP-US subregion may only have 58,700 MW to meet a 65,000 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Although baseload resources account for roughly 50,200 MW, the low availability end of the spectrum would only see a loss of 8,800 MW. However, solar resources total 3,600 MW of availability but could expect to lose 2,000 MW, or over half, on a low availability end of the spectrum.

For this scenario, there were approximately 1,100 MW of additional coal retirements included in this subregion.

Planning Reserve Margin

Given the growing variability, a 15-21% margin for the NWPP-US subregion is close to the median level of reserve margin needed to maintain reliability, it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 42%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 18,200 MW or 28% of the expected peak demand. As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Risk Scenario Results

For the SRSG region, the reliability indices are summarized in **Table 9.3**.

Table 9.3: Reliability Index Comparison-NWPP-US						
Reliability Index	**2022 Base Case**	**2022 Scenario**	**2022 Delta**	**2024 Base Case**	**2024 Scenario**	**2024 Delta**
EUE [MWh]	12,799	14,681	1,882	248,573	274,091	25,518
EUE [ppm]	33	38	5	622	686	64
LOLH [hrs/yr]	0.25	0.28	0.03	4.4	6.2	1.8

Annual Demand at Risk

In 2022, for the scenario, the NWPP-US subregion could experience less than one hour where the 1-day-in-10-years LOLE threshold of resource adequacy is not maintained and just over six hours by 2024. For the Base Case, the results were less than an hour in 2022 and four hours in 2024. The impacts of the scenario came from the 1,100 MW coal retirement as well as impacts from external assistance in other subregions.

Hours at Risk

A system wide high demand scenario would eliminate much of the external assistance available for NWPP-US, causing the hours where simulated load exceeded available resources to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the NWPP-US subregion is expected to have many hours where the 1-day-in-10-years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Energy at Risk

In 2022, about 37 per million MWh of energy is at risk in the scenario case and grows to nearly 685 per million MWh by 2024. In the Base Case, the results were 32 and 621 per million MWh, respectively. For the six hours of potential demand at risk in the scenario results, this would equate to approximately 110 per million MWh on average in 2024.

WECC-Alberta and British Columbia (WECC-AB and WECC-BC)

The WECC-AB subregion covers the Alberta province of Canada while the WECC-BC subregion covers the British Columbia province. Both subregions are winter peaking.

Demand

The WECC-AB subregion is expected to peak in early-February at approximately 9,200 MW in 2022 and 2024. Overall, the WECC-AB subregion should expect a 30% ramp, or 2,100 MW, from the lowest to the highest demand hour of the peak demand day. In 2022, there is a 5% possibility the subregion could peak as high as 9,500 MW, which equates to a 3% load forecast uncertainty.

The WECC-BC subregion is expected to peak in mid-January at approximately 9,300 MW in 2022 and 9,600 MW in 2024. Overall, the WECC-BC subregion should expect a 49% ramp, or 3,000 MW, from the lowest to the highest demand hour of the peak demand day. In 2022, there is a 5% possibility the subregion could peak as high as 10,000 MW, which equates to an 11% load forecast uncertainty.

Resource Availability

In the WEC-AB subregion, the expected availability of resources on the peak hour in 2022 is 13,300 MW and 11,000 MW in 2024. Under low-resource availability conditions, the WECC-AB subregion may only have 12,000 MW to meet a 9,200 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 12,300 MW, the low availability end of the spectrum would only see a loss of 500 MW. However, wind resources total 700 MW of availability but this entire resource could be lost on a low availability end of the spectrum.

In the WECC-BC subregion, the expected availability of resources on the peak hour in 2022 and 2024 is 12,900 MW. Under low-resource availability conditions, the WECC-BC subregion may only have 10,600 MW available to meet a 9,300 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 1,000 MW, the low availability end of the spectrum would only see a loss of 100 MW or 10%. However, hydro resources total 11,800 MW but could lose 2,100 MW of this resource (about 20%) on a low availability end of the spectrum. For this scenario, there were approximately 800 MW of additional coal retirements included in the WECC–AB subregion and zero in WECC-BC.

Planning Reserve Margin

Given the growing variability, a 15% margin for the WECC-AB subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum needed for all hours. The highest reserve margin needed is expected to be around 22%, so it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 1,700 MW, or 19% of the expected peak demand.

Given the growing variability, a 15% margin for the WECC-BC subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 42%, equating to approximately 2,800 MW (or 31%) of the expected peak demand.

As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Risk Scenario Results

For the scenario in the Canadian areas in WECC, both Canada subregions showed no expected LOLH or EUE. For the Canadian subregions, the coal resource portion of the generation portfolio is small, and removal of the coal resources had little to no impact on the resource adequacy of these subregions. This is based on the sum **Table 9.4**.

Table 9.1: Reliability Index Comparison-Alberta and British Columbia

Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
Alberta						
EUE [MWh]	0	0	0	0	0	0
EUE [ppm]	0	0	0	0	0	0
LOLH [hrs/yr]	0	0	0	0	0	0
British Columbia						
EUE [MWh]	19	0	-19	8	0	-8
EUE [ppm]	0.323	0	-0.323	0.137	0	-0.137
LOLH [hrs/yr]	0.001	0	-0.001	0.001	0	-0.001

Appendix A: Assessment Preparation, Design, and Data Concepts

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Assessment Data Questions

Direct all data inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the *2020 NERC ProbA.*[29] However, extensive reproduction of tables and/or charts will require permission from the NERC staff and PAWG members listed in the table below:

NERC Probabilistic Assessment Working Group (PAWG) Members

Name:	Organization:	Name:	Organization:
Andreas Klaube	Chair; NPCC	Julie Jin	ERCOT
Alex Crawford	Vice Chair; Southwest Power Pool, Inc.	Peter Warnken	ERCOT
John Skeath	North American Electric Reliability, Corp.	Sennoun Abdelhakim	Hydro-Québec
Salva Andiappan	Midwest Reliability Organization	Lewis De La Rosa	TRE
Guarav Maingi	SaskPower	David Richardson	Independent Electricity System Operator
Bagen Bagen	Manitoba Hydro	Vithy Vithyananthan	Independent Electricity System Operator
Darius Monson	Midcontinent Independent System Operator	Anna Lafoyiannis	Independent Electricity System Operator
Phil Fedora	NPCC	Richard Becker	SERC Reliability Corporation
Peter Wong	ISO New England, Inc.	Anaisha Jaykumar	SERC Reliability Corporation
Manasa Kotha	ISO New England, Inc.	Wyatt Ellertson	Entergy
Laura Popa	New York ISO	Patricio Rocha-Garrido	PJM Interconnection, L.L.C.
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Mike Welch	New York ISO	Tim FryFogle	ReliabilityFirst
Benjamin O'Rourke	New York ISO	William Lamanna	North American Electric Reliability, Corp.
Bryon Domgaard	WECC	Amanda Sargent	WECC
Matt Elkins	WECC		

[29] NERC_LTRA_2020.pdf

Appendix B: Description of Study Method in the ProbA

Descriptions and assumptions of each RE's probabilistic model are detailed in the sections below. Where an RE is not listed, information was not provided at time of publication but may be provided through contact via information listed in **Appendix A**.

MRO-MISO

General description

MISO utilized the Strategic Energy Risk Valuation Model (SERVM) to perform the 2020 ProbA Base Case and scenario. 30 historic weather years were modeled with five different economic uncertainty multipliers and 125 outage draws resulting in 18,750 unique load/outage scenarios being analyzed. In SERVM the MISO system was represented as a transportation model with each of MISO's 10 LRZ's modeled with their respective load forecasts and resource mixes. The LRZ's were able to import and export energy with each other within the model and the results of the study were aggregated up to the MISO level.

Demand and LFU

To account for load uncertainty due to weather, MISO modeled 30 unique load shapes based on historic weather patterns. These load shapes were developed by using a neural-net software to create functional relationships between demand and weather with the most recent 5 years of actual demand and weather data within MISO. These neural-net relationships were then applied to the most recent 30 years of weather data to create 30 synthetic load shapes based on historic weather. Finally, the average of these 30 load shapes was scaled to the 50-50 forecasts from MISO's Load Serving Entities (LSE's).

To capture economic uncertainty in peak demand forecasts, MISO modeled each of the 30 load shapes with 5 different scalars (-2%, -1%, 0%, 1%, 2%). This resulted in 150 unique load scenarios (30 load shapes X 5 uncertainty scalars) being modeled.

Thermal Resources

All thermal resources in MISO were modeled as two-state units (i.e., either dispatched to full installed capacity or off-line). Units with at least one year of operating history were modeled with their actual EFORd based on GADS data (up to five historic years). Units with insufficient operating history to determine an EFORd were assigned the class average EFORd.

Wind and Solar

Wind units were modeled with monthly ELCC values that can be found in MISO's 2021-22 PY LOLE Study Report. Solar resources were modeled at 50% of installed capacity. Both wind and solar were treated as a net-load reduction within the model.

Hydroelectric

Hydro units in MISO were modeled as a resource with an EFORd except for run-of-river units. These were modeled at their individual capacity credit which is determined by the resources historic performance during peak hours.

Demand-Side Resources

DR was modeled as dispatchable call limited resources. These resources were only dispatched when needed during emergency conditions to avoid shedding load. Energy efficiency resources were modeled as load modifiers that were netted from the load within the model.

Transmission
Capacity import limits and capacity export limits were modeled for each of the 10 LRZ's. If an LRZ was expected to be unable to meet its peak demand, then that zone would import capacity up to its capacity import limits, provided that there were sufficient exports available from other zones.

MRO-SaskPower

General description
Saskatchewan utilizes the MARS program for reliability planning. The software performs the Monte Carlo simulation by stepping through the time chronologically and calculates the standard reliability indices of daily and hourly LOLE and EUE.

Detailed representation of the utility system (e.g., load forecast, expansion sequence, unit characteristics, maintenance, outages) are included in the model. The model simultaneously considers many types of randomly occurring events, such as forced outages of generating units. Based on the deterministic calculations within this assessment, Saskatchewan's anticipated reserve margin is 34.2% and 30.0%, for years 2022 and 2024 respectively. EUE calculated for Base Case is 80.4 MWh and 26.4 MWh for the years 2022 and 2024, respectively. LOLH follows a similar pattern to EUE.

Demand and LFU
This reliability study is based on the 50/50 load forecast that includes data like the annual peak, annual target energy, and load profiles. The model distributes the annual energy into hourly data based on the load shape. Saskatchewan develops energy and peak demand forecasts based on the provincial econometric model forecasted industrial load data and the weather normalization model.

The forecasts also take into consideration of the Saskatchewan economic forecast, historic energy sales, customer forecasts, weather normalized sales, and system losses. Load forecast uncertainty is explicitly modeled by utilizing a seven-step normal distribution with a standard deviation of ±3%, 5% and 10%.

Thermal Resources
Natural gas units are typically modeled as two-state units so that natural gas units are either available to be dispatched up to full load or is on a full forced outage with zero generation. Coal facilities are typically modeled as three-state units. Coal units can be at a full load, derated forced outage, or a full forced-outage state. Forecast derated hours are based on the percentage of the time the unit was derated out of all hours, excluding planned outages, based on the five-year historical average. Generally, we use Utilization Forced Outage Probability[30] when forecasting reliability for the natural gas turbine units and Forced Outage Rate or Derated Adjusted Forced Outage Rate for the steam units.

Wind and Solar
For reliability planning purposes, Saskatchewan plans for 10% of wind nameplate capacity to be available to meet summer peak and 20% of wind nameplate capacity to be available to meet winter peak demand. Two methods were utilized to carry out the analysis for determining wind capacity credit. The first method approximates the effective load carrying capability (ELCC) of the wind turbines by determining the wind capacity during peak load hours of each month by looking at historical wind generation in those hours. A period of four consecutive hours was selected and the actual wind generation in those four hours was used to determine the ELCC of the wind turbines. The median capacity value of wind generation in those four hours of each day of the month is calculated and is converted to a percent capacity by dividing that number by the maximum capacity of the wind turbine. The second method to estimate the ELCC was also utilized by looking at the top 1%, 5%, 10%, and 30% of load hours in each month opposed

[30] Note that this is equivalent to Forced Outage Rate demand (FORd) used in other NERC and industry documents.

to a consecutive period of four hours. With these methods, SaskPower then looked at the lowest averages from both methods in each of the winter and summer months to come up with the wind capacity credit value.

Currently, Saskatchewan has a low penetration level of solar resources and most of it is made up of distributed energy resources that are netted off the load forecast.

Hydroelectric

Hydro generation is modeled as an energy-limited resource and the annual hydro energy is calculated based on the historical data that has been accumulated over the last 30+ years. Hydro units are described by specifying maximum rating, minimum rating, and monthly available energy. The first step is to dispatch the minimum rating for all the hours in the month. Remaining capacity and energy are then scheduled to reduce the peak loads as much as possible.

Demand-side resources

Controllable and Dispatchable Demand Response Program*:* DR is modelled as an emergency operating procedure by assigning a fixed capacity value (60 MW) and thus configured as a negative margin state for which MARS evaluates the required metrics. An emergency operating procedure is initiated when the reserve conditions on a system approach critical level.

Energy provided from energy efficiency and conservation programs is netted off the load forecast.

Transmission

No transmission facility data is used in this assessment as the model assumes that all firm capacity resources are deliverable within the assessment area. Separate transmission planning assessments indicate that transmission capability is expected to be adequate to supply firm customer demand and planned transmission service for generation sources.

MRO-SPP

General description

The Southwest Power Pool 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 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. The SPP assessment area has over 90,000 MW (name plate) of total generation, including over 28,000 MW of nameplate wind generation. SPP is also a summer-peaking assessment area at approximately 51,000 MW of summer peak demand.

Demand and LFU

Eight years (2012–2019) of historical hourly load data were individually modeled to produce 8,760 hourly load profiles for each zone in the SPP assessment area. In order to not overestimate the peak demand, the forecasted peak demand for 2022 and 2024 was assigned to the load shape from 2014 (the median year of the eight historical years). The other seven years were also scaled to a forecasted peak demand calculated by distributing the variance between the peaks of the non-median years to the median year.

Microsoft Excel was used to regress the daily peak values against temperatures, economics, and previous daily peak loads observed at key weather stations throughout the SPP footprint to derive the load forecast uncertainty components. The load multipliers were determined from a uniform distribution and assigned seven discrete steps with the applicable probability occurrence weighting. All seven of the load forecast uncertainty steps were modeled at or above the 50/50 peak forecast.

Thermal Resources
SPP modeled seasonal maximum net capabilities reported in the LTRA for thermal resources. Physical and economic parameters were modeled to reflect physical attributes and capabilities of the resources. Full and partial forced outages from NERC GADS data in the SPP footprint were applied on a resource basis.

Wind and Solar
SPP included wind and solar resources currently installed, under construction, or that have a signed interconnection agreement. Wind and solar resources were modeled in SERVM with an hourly generation profile assigned to each individual resource. Hourly generation is based upon historical profiles correlating with the yearly load shapes (2012 to 2019). Any resources that did not have historical shapes were supplemented by the nearest resource.

Hydroelectric
Hydro generation was modeled as an energy limited resource while considering monthly hydro energy limitations that were calculated with historical data from 2012 to 2019. Hydro resources also considered historical daily max energies and the software dispatched by the resources as needed to maintain reliability.

Demand-side resources
Controllable and dispatchable DR programs were modelled as equivalent thermal units with high fuel costs so that those units would be dispatched last to reflect demand-response operating scenarios to prevent loss of load events.

Transmission
The SPP transmission system was represented as “pipes” between six zones modeled in the SPP assessment area. A first contingency incremental transfer capability analysis was performed outside of the SERVM software that determined transfer limits modeled between zones. All resources and loads in their respective zones were modeled as a “copper sheet” system.

NPCC- Maritimes

General description
The Maritimes assessment area is winter peaking and part of NPCC with a single RC and two BA areas. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, Prince Edward Island, and the northern portion of Maine, which is radially connected to New Brunswick. The area covers 58,000 square miles with a total population of 1.9 million.

Demand and LFU
The Maritimes area demand is the maximum of the hourly sums of the individual subarea load forecasts. Except for the Northern Maine subarea that uses a simple scaling factor, all subareas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modeling, and end-use modeling to develop their load forecasts. Annual peak demand in the Maritimes area varies by +9% of forecasted Maritimes area demand based upon the 90/10 percentage points of load forecast uncertainty (LFU) distributions.

Thermal Resources
The Maritimes area uses seasonal dependable maximum net capability to establish combustion turbine capacity for resource adequacy. During summer, these values are derated accordingly.

Wind
The Maritimes area provides an hourly historical wind profile for each of its four subareas based on actual wind shapes for the 2012–2018 period. The wind in any hour is a probabilistic amount determined by selecting a random wind and load shape from the historic years. Each subarea’s actual MW wind output was normalized by the total installed capacity in the subarea during that calendar year. These profiles, when multiplied by current subarea total installed wind capacities, yield an annual wind forecast for each subarea. The sum of these four subarea forecasts represents the Maritimes area’s hourly wind forecast.

Solar
Solar capacity in the Maritimes area is behind the meter and netted against load forecasts. It does not currently count as capacity.

Hydroelectric
Hydro capacity in the Maritimes area is predominantly run of the river, but enough storage is available for full rated capability during daily peak load periods.

Demand-side resources
Plans to develop up to 120 MW by 2029/2030 of controllable direct load control programs by 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 this 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 196 MW while the annual amounts for winter peak demand reductions rise from 93 MW to 465 MW.

Transmission
Construction of a 475 MW +/-200 kV HVDC undersea cable link (the Maritime Link) between Newfoundland and Labrador and Nova Scotia 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 Nova Scotia in 2021. 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 Nova Scotia into New Brunswick that would reduce transmission loading in the southeastern New Brunswick area.

Other
The current amount of DERs in the Maritimes area is currently insignificant at about 29 MW in winter. During this LTRA period, additions of solar (mainly rooftop) resources in Nova Scotia are expected to increase this value to about 184 MW. The capacity contribution of rooftop solar during the peak is zero as system winter peaks occur during darkness. As more installations are phased in, operational challenges like ramping and light load conditions will be considered and mitigation techniques investigated.

NPCC- New England

General description
ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It 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 process for the regional BPS. The New England BPS serves approximately 14.5 million people over 68,000 square miles.

Demand and LFU
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 demand forecast are considered coincident. This demand forecast is the gross demand forecast that is then decreased to a net forecast by subtracting the impacts of energy efficiency measures and behind the meter photovoltaic (PV). Annual peak demand in the New England area varies by +11% of forecasted New England area demand based upon the 90/10% points of LFU distributions.

Thermal Resources
The seasonal claimed capability as established through claimed capability audit is used to rate the sustainable maximum capacity of nonintermittent thermal resources. The seasonal claimed capability for intermittent thermal resources is based on their historical median net real power output during ISO-NE-defined seasonal reliability hours.

Wind
New England models wind resources use the seasonal claimed capability that is based on their historical median net real power output during seasonal reliability hours.

Solar
Most of the solar resource development in New England consists of the state-sponsored distributed behind the meter PV resources that do not participate in the wholesale electricity markets but reduce the real-time system load observed by ISO-NE system operators. These resources are modeled as load modifiers on an hourly basis based on the 2002 historical hourly weather profile.

Hydroelectric
New England uses the seasonal claimed capability to represent hydroelectric resources. The seasonal claimed capability for intermittent hydro-electric resources is based on their historical median net real power output during seasonal reliability hours.

Demand-side resources
On June 1, 2018, ISO-NE integrated price-responsive DR into the energy and reserve markets. Currently, approximately 584 MW of DR participates in these markets and is dispatchable (i.e., treated like generators). Regional DR will increase to 592 MW by 2023, and this value is assumed constant/available thru the remainder of the assessment period.

Transmission
The area has constructed several major reliability-based transmission projects within the past few years to strengthen the regional BPS. While several major projects are nearing completion, two significant projects remain under construction: The Greater Boston project and the Southeastern Massachusetts and Rhode Island project. The majority of the Greater Boston project will be in-service by December 2021 while the addition of a 115 kV line between Sudbury and Hudson is expected to be in service by December 2023. The Southeastern Massachusetts and Rhode Island project is in the early stages of construction. Additional future reliability concerns have been identified in Boston and are being addressed through a development request-for-proposal.

Other
New England has 174 MW (1,379 MW nameplate) of wind generation and 787 MW (2,164 MW nameplate) behind the meter PV. Approximately 12,400 MW (nameplate) of wind generation projects have requested generation interconnection studies. Behind the meter PV is forecast to grow to 1,062 MW (4,306 MW nameplate) by 2029. The behind the meter PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day, decreasing from 34.3% of nameplate in 2020 to about 23.8% in 2029.

NPCC-New York
General description
The NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only BA within the state of New York. The transmission grid of New York State encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.5 million people. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Demand and LFU

The energy and peak load forecasts are based upon end-use models that incorporate forecasts of economic drivers and end-use technology efficiency and saturation trends. The impacts of energy efficiency and technology trends are largely incorporated directly in the forecast model with additional adjustments for policy-driven energy efficiency impacts made where needed. The impacts of DERs, electric vehicles, other electrification, energy storage, and behind the meter solar PV are made exogenous to the model. At the system level, annual peak demand forecasts range from 6% above the baseline for the ninetieth percentile forecast to 8% below the baseline for the tenth percentile forecast. These peak forecast variations due to weather are reflected in the LFU distributions applied to the load shapes within the MARS model.

Thermal Resources

Installed capacity values for thermal units are based on the minimum of seasonal dependable maximum net capability test results and the capacity resource interconnection service MW values. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled using a multi-state representation that represents an EFORd.

Wind

New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period for each wind plant based on production data. Wind seasonality is captured by randomly selecting an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.

Solar

New York provides 8,760 hours of historical solar MW profiles for each year of the most recent five-year calendar period for each solar plant based on production data. Solar seasonality is captured by randomly selecting an annual solar shape for each solar unit in each draw. Each solar shape is equally weighted.

Hydroelectric

Large New York hydro units are modeled as thermal units with a corresponding multistate representation that represents an EFORd. For run-of-river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run-of-river unit seasonality is captured by randomly selecting an annual shape for each run-of-river unit in each draw. Each shape is equally weighted.

Demand-side resources

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.

Transmission

The 2020–2021 reliability planning process includes proposed transmission projects and transmission owner local transmission plans that have met the RPP inclusion rules. The NYISO Board of Directors selected projects under two public policy transmission planning processes: the first for Western New York and the second for Central New York and the Hudson Valley. These projects are known to meet an AC transmission need. When completed, these projects will add more transfer capability in Western New York and between Upstate and Downstate New York.

Other

The NYISO is currently implementing a three-to-five year plan to integrate DERs, including DR resources, into its energy, capacity, and ancillary services markets. The NYISO published a DER roadmap document in February 2017 that outlined NYISO's vision for DER market integration. The FERC approved the NYISO's proposed tariff changes in

January 2020. The NYISO is currently identifying the related software and procedure changes and is targeting implementation in Q4 2021.[31]

NPCC- Ontario

General description

The IESO is the BA for the province of Ontario. The province of Ontario covers more than one million square kilometers (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.

Demand and LFU

Each zone has an hourly load from the demand forecast as well as a monthly LFU distribution. The LFU is derived by simulating the effect of many years of historical weather on forecasted loads. Monthly distributions of simulated demand peaks are generated at a zonal level and then adjusted to match the equivalent distribution at the provincial level.

The adjusted LFU distributions are used to create a seven-step approximation of the actual distribution. When generating reliability indices, the MARS model assesses all seven steps of the LFU distribution, weighted by probability. Annual peak demand in the Ontario area varies by +11% of forecasted Ontario area demand based upon the 90/10% points of LFU distributions.

Thermal Resources

The capacity values and planned outage schedules for thermal units are based on information submitted by market participants. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data. For existing units with insufficient historical data and for new units, capacity states and state transition rate data of existing units with similar size and technical characteristics are applied.

Wind

Historical hourly load profiles are used to model wind generation. Wind generation is aggregated by zone. For the Monte Carlo analysis, the model randomly selects a different yearly simulated profile during each iteration.

Solar

Historical hourly profiles are used to model solar generation. Solar generation is aggregated by zone. In the Monte Carlo analysis, the model randomly shuffles the order of the days within each month for solar production in each iteration.

Hydroelectric

Hydroelectric generation is modelled by using three inputs: a run-of-river component (which simulates the range of historical water availability), a maximum dispatchable capacity, and a dispatchable energy. Input values are calculated by using a combination of historic hourly maximum offer data and historic hourly production data aggregated on a zonal level. The three inputs work together to simulate the range of historical water conditions that have been experienced since market opening in 2002.

Demand-side resources

The IESO models two demand-side resources as supply resources: DR and dispatchable loads (DL). Both measures are modelled on an as-needed basis in MARS and will only be used when all other supply-side resources are insufficient to meet demand. DR and DL capacity is aggregated by IESO zone.

[31] Distributed Energy Resources (DER) - NYISO

Transmission

The IESO-controlled grid is modelled by using 10 electrical zones with connecting transmission interfaces. Transmission transfer capabilities are developed according to NERC standard requirements; the methodology for developing transmission transfer capabilities is described in the IESO's *Transfer Capability Assessment Methodology: For Transmission Planning Studies.*[32]

NPCC- Quebec

General description

The Québec assessment area (province of Québec) is winter-peaking and part of NPCC. It covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America and has 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 and LFU

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. Annual peak demand in the Quebec area varies by +9% of forecasted Ontario area demand based upon the 90/10% points of load forecast LFU distributions.

Thermal Resources

For thermal units, maximum capacity in the Québec area is defined as the net output a unit can sustain over a two-consecutive-hour period.

Wind

In Quebec, wind capacity credit is set for winter as the system is winter peaking. The capacity credit of wind generation is based on a historical simulated data adjusted with actual data of all wind plants in service in 2015. For the summer period, wind power generation is derated by 100%.

Solar

In Québec, behind the meter generation (solar and wind) is estimated at approximately 10 MW and doesn't affect the load monitored from a network perspective.

Hydroelectric

In Québec, hydro resources maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Demand-side resources

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, which is mainly designed for large industrial customers; it has an impact of 1,730 MW on Winter 2020–2021 peak demand. The area is also expanding its existing interruptible load program for commercial buildings; this program will have an impact of 310 MW in 2020–2021, 150 MW for Winter 2021–2022, and then 300 MW by 2026–2027. Another similar program for residential customers is under development and should gradually rise from 57 MW for Winter 2020–2021 to 621 MW for Winter 2030–2031.

[32] Transfer Capability Assessment Methodology: For Transmission Planning Studies

Transmission

The Romaine River Hydro Complex Integration project is presently underway; its total capacity will be 1,550 MW. Romaine-2 (640 MW) has been commissioned in 2014, Romaine-1 (270 MW) in 2015, and Romaine-3 (395 MW) in 2017. Romaine-4 (245 MW) was planned be in service in 2020, but its commissioning is delayed to 2022. A new 735 kV line that extends some 250 km (155 miles) between Micoua substation in the Côte-Nord area and Saguenay substation in Saguenay–Lac–Saint-Jean is now under construction phase and is planned to be in service in 2022. The project also includes adding equipment to both substations and expanding Saguenay substation.

Other

Total installed behind the meter capacity (solar PV) is expected to increase to more than 500 MW in 2031. 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 2020–2021 to 10 MW for Winter 2030–2031. No potential operational impacts of DERs are expected in the Quebec area, considering the low DER penetration in the area.

SERC

General description

SERC covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC utilizes General Electric MARS software an 8,760 hourly load, generation, and transmission sequential Monte Carlo simulation model consisting of fifteen interconnected areas, four of which are SERC's NERC assessment areas (SERC-E, SERC-C, SERC-SE, and SERC-FP). All assumptions and methods are described below and apply to the assessment areas.

Demand and LFU

For this study, annual load shapes for the seven years between 2007 and 2013 were used to develop the Base Case load model. Each of the hourly load profiles developed from the historical loads were then adjusted to model the seasonal peaks and annual energies reported in the 2020 SERC LTRA filings. Except for SERC-FP, all assessment areas are winter peaking. This study accounted for LFU in two ways. The first was to utilize seven different load shapes, representing seven years of historical weather patterns from 2007 through 2013. The second way is through multipliers on the projected seasonal peak load and the probability of occurrence for each load level. Annual peak demand varies by the following load forecast uncertainty, SERC-C: 4.75%, SERC-E: 3.95%, SERC-SE-6.11%, SERC-FP: 4.04%.

Thermal Resources

The three categories modeled in this study were thermal, energy-limited, and hourly resources. Most of the generating units were modeled as thermal units for which the program assumes that the unit is always available to provide capacity unless it is on planned or forced outage. All the thermal units were modeled with two capacity states, either available or on forced outage.

The data for the individual units modeled in the SERC assessment areas was taken from the 2020 LTRA filings.

Wind and Solar

Wind and solar profiles for the units in the SERC footprint were represented using hourly generation time series. To represent the 2007–2013 meteorology, corresponding to the historical hourly load profiles, simulated production profiles were used. These profiles were extracted from available datasets from the National Renewable Energy Laboratory.

Five distinct sites were chosen for each assessment area, to represent existing wind farm locations. Similarly, five locations per SERC MRA were selected to create the solar profiles. Each site data was converted to power and aggregated to produce a typical solar shape per assessment area. To improve the robustness of the results, the study team used a 7-day sliding window method in the selection of wind and solar data.

Hydroelectric

MARS schedules the dispatch of hydro units in two steps. The minimum rating of each unit is set to 20% of the nameplate capacity, representing the run-of-river portion of the unit and is dispatched across all hours of the month. Any remaining capacity and energy are then scheduled on an hourly basis as needed to serve any load that cannot be met by the thermal generation on the system. Hydro units are modeled as energy limited resources, and their capacity factors (the ratio of the energy output to the maximum possible if operated at full output for all of the hours in the period) are an indication of their contribution to meeting load. Energy-limited resources have a zero forced-outage rate.

The hydro unit data was extracted from the ABB Velocity Suite database and then adjusted to match the seasonal ratings of the units from the 2020 LTRA data. The monthly energy available is the average over the last 10 years of generation for each plant.

Demand-side resources

Demand-side resources are incorporated as an energy-limited resource with an annual energy megawatt hour limitation. These resources will be second in priority to thermal and variable generation to serve load. DR is modeled for all SERC assessment areas. For externals areas, these resources are modeled as emergency operating procedures, using the values from their LTRA submissions.

Transmission

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of area. First contingency incremental transfer capability values for interface limits are modeled for the system. The assumption within areas is a copper sheet system (full capacity deliverability).

Texas-RE-ERCOT

General description

The Electric Reliability Council of Texas (ERCOT) area encompasses about 75% of the land area in Texas. The grid delivers approximately 90% of the electricity used by more than 26 million consumers in Texas. The ProbA with SERVM captured the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring areas as stochastic variables. The model performed 10,000 hourly simulations for each study year to calculate physical reliability metrics. The 10,000 hourly simulations were derived from 40 weather years, 5 load forecast multipliers, and 50 Monte Carlo unit outage draws.

Demand and LFU

ERCOT developed a 50/50 peak load forecast that represented the average peak load from 40 synthetic load profiles, each representing the expected load in a future year given the weather patterns from each of the last 40 years of history. Annual peak demand in ERCOT varied by +2.1% based upon the ninetieth percentile distribution. Each synthetic weather year was given equal probability of occurring. Five load forecast uncertainty multipliers were applied to each of the 40 synthetic weather years. The multipliers that range from -4% to +4% captured economic load growth uncertainty.

Thermal Resources

Conventional generators were modeled in detail with maximum capacities, minimum capacities, heat rate curves, startup times, minimum up and down times, and ramp rates. The winter and summer capacity ratings were based on ERCOT's LTRA report. SERVM's Monte Carlo forced outage logic incorporated full and partial outages based on historical operations.

Wind and Solar

Wind and solar resources were modeled as capacity resources with 40 historical weather years that consist of hourly profiles that coincide with the load and hydro years. The assumed peak capacity contributions for reserve margin accounting were 63% for coastal wind, 29% for panhandle wind, 16% for other wind, and 76% for solar. The actual reliability contributions were based on the hourly modeled profiles.

Hydroelectric

Dispatch heuristics for hydro resources were developed from eight years of hourly data provided by ERCOT, applied to 40 years of monthly data from FERC 923 and ERCOT, and modeled with different parameters for each month, including total energy output, daily maximum and minimum outputs, and monthly maximum output. A separate energy-limited hydro resource was modeled to represent additional capability during emergency conditions.

Demand-Side Resources

Interruptible load and DR resources were captured as resources with specific price thresholds at which each resource is dispatched. These resources were also modeled with call limits and energy emergency alert level.

Transmission

SERVM is a state-of-the-art reliability and hourly production cost simulation tool that performs an hourly chronological economic commitment and dispatch for multiple zones using a transportation/pipeline representation. ERCOT was modeled as a single region with ties to SPP, Entergy, and Mexico to reflect historical import/export activity and potential assistance. 1,220 MW of high voltage direct current interties were included in this study.

WECC

General description

The Multiple Area Variable Resource Integration Convolution (MAVRIC) model was developed to capture many of the functions needed in the Western Interconnection for probabilistic modeling. The Western Interconnection has many transmission connections between demand and supply points with energy transfers being a large part of the interconnection operation. A model was needed that could factor in dynamic imports from neighboring areas. The Western Interconnection has a large geographical footprint with winter-peaking and summer-peaking load-serving areas, and a large amount of hydro capacity that experiences large springtime variability. The ability to study all hours of the year on a timely run-time basis was essential for the probabilistic modeling of the interconnection. Additionally, the large portfolio penetration of variable energy resources, and the different generation patterns depending on the geographical location of these resources, called for correlation capability in scenario planning. MAVRIC is a convolution model that calculates resource adequacy through loss-of-load probabilities (LOLPs) on each of the stand-alone (without transmission) load-serving areas. The model then calculates the LOLP through balancing the system with transmission to a probabilistic LOLP. Finally, MAVRIC can supply hourly demand, VER output, and baseload generation profiles that can be used in production cost and scenario planning models. **Figure B.1** provides the high-level logic diagram of the processes MAVRIC performs.

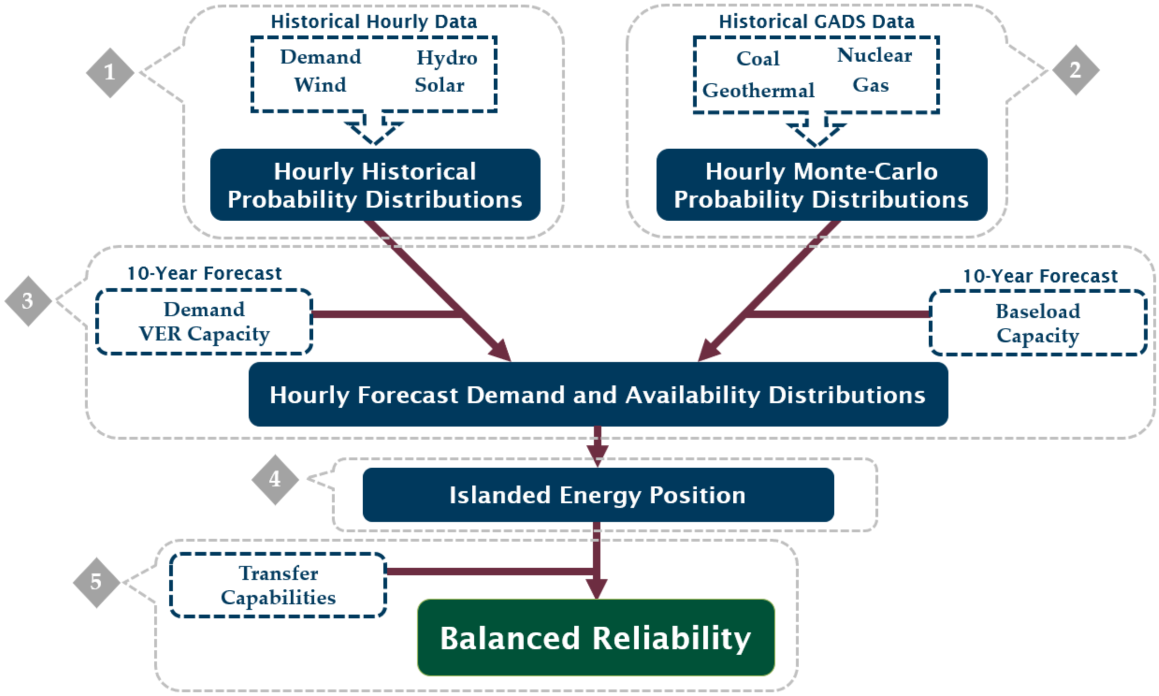

Figure B.1: MAVRIC Process Flowchart

There are many ways to perform probabilistic studies and each has its strengths and weaknesses. The tool used to perform the calculations depends on the system and the desired output that is being analyzed. The MAVRIC model was developed to enhance the probabilistic capabilities at WECC. It allows WECC to perform independent reliability assessments of the Western Interconnection, a system that is geographically diverse and dependent on transfer capabilities. Using convolution techniques and Monte-Carlo simulations and with the ability to use transfers dynamically, the tool models the overall resource adequacy of the Western Interconnection while maintaining adequate run-time and computing capabilities.

Demand and LFU

Probability distributions for the demand variability are determined by aligning historical hourly demand data to each of the Balancing Authorities in the database. The first Sundays of each historical year are aligned so that weekends and weekdays are consistent. Each hour is then compared against a rolling seven-week average for the same hour of the same weekday. This establishes the difference between the historical hour and the average. MAVRIC uses each of these percentages to calculate a percentile probability for a given hour based on the variability of the three weeks before and three weeks after the given hour for each of the historical years. The output is a series of hourly percentile profiles with different probabilities of occurring.

Thermal Resources

The distributions of the baseload resources, nuclear, coal-fired, natural-gas-fired, and (in some cases) biofuel and geothermal resources is determined by using the historical rate of unexpected failure and the time to return to service from the NERC Generation Availability Data System. Generator operators submit data that summarizes expected and unexpected outages that occur to their generating units. The annual frequency and recovery time for the unexpected outages is used to calculate the availability probability distributions for baseload resources. Through Monte-Carlo random sampling, MAVRIC performs 1,000 iterations for each resource, calculating the available capacity on an hourly basis for all hours of a given year. The model randomly applies outages to units throughout the year adhering to the annual frequency of outage rates for those units. Once a unit is made unavailable, the mean time to recovery is adhered to, meaning for a certain period of hours after the unexpected failure, that unit remains unavailable. The total available baseload capacity for each load serving area for each hour is then computed and stored as a sample in a database. After 1,000 iterations, the data points of availability for each hour are used to generate availability probability distributions. The output of this process is consistent with the variable energy resource distributions in that a series of hourly percentile profiles with different probabilities of occurring is produced.

Wind and Solar/Hydroelectric

Determining the availability probability distributions for the variable energy resources (water, wind, and solar-fueled resources) is conducted like the demand calculations but with two notable differences:

- The first, and most significant, difference is the time frame used to calculate the variable energy resource availability probability distributions. For variable energy resource fuel sources, the day of the week does not influence the variability of weather. Therefore, the need to use the data from the same day of the week is not necessary. This allows the variable energy resource distributions to be condensed to a rolling seven-day window by using the same hour for each of the seven days of the scenario.
- The second difference is that the historical generation data is compared against the available capacity to determine the historical capacity factor for that hour to be used in the percentile probability calculation. The output of this process is a series of hourly percentile profiles with different probabilities of occurring.

Demand-side resources

A significant portion of the controllable DR/demand-side management programs within the Western Interconnection are associated with large industrial facilities, air conditioner cycling programs, and water pumping both for canal or underground potable water as well as for irrigation. These programs are created by load serving entities 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 demand side management programs are approved by local authorities and used only for the benefit of the approved load serving entity. Demand side management 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.

Transmission

MAVRIC goes through a step-by-step balancing logic where excess energy that is energy above an area's planning reserve margin to maintain the resource adequacy threshold can be used to satisfy another area's resource adequacy shortfalls. This is dependent on the neighboring areas having excess energy as well as there being enough transfer capability between the two areas to allow the excess energy to flow to the deficit area. MAVRIC analyzes first order transfers (external assistance from an immediate neighbor) and second order transfers (external assistance from an immediate neighbor's immediate neighbors) in all cases while checking for sufficient transfer capacity. After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system where needed. The end result is an analysis of the entire system, reflecting the ability of all load-serving areas to maintain a resource adequacy planning reserve margin equal to or less than the threshold. Analysis is then done on any areas where the threshold margin cannot be maintained even after external assistance from excess load-serving areas.

Other

Planning Reserve Margins: For each hour, the demand and availability distributions are compared to one another to determine the amount of "overlap" in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions represents the LOLP. This would be the accumulative probability associated with the overlap. If the probability is greater than the selected threshold, then there is a resource adequacy shortfall in that area for that hour. A resource adequacy threshold Planning Reserve Margin can be determined to identify the Planning Reserve Margin needed to maintain a level of LOLP at or less than the threshold.

Appendix C: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
Model Used	**Name**	GE MARS	GE MARS	GE MARS	GE-MARS	GE MARS	GE MARS	SERVM	SERVM	MAVRIC
	Model Type	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Convolution
	# Trials	1,000*7	1,000*7	1,000*10*7	50000 * 7	10000	20000 x 7	28,000	50 x 40 x 5	N/A
	Total Run Time	2 hours * 72 CPUs	2 hours * 40 CPUs	50 min * 720 CPUs	3 Hours	35 min	0.5 hours	30 hours/Study Year; 35 processors	7 hours; 25 cores	N/A
Load	**Internal Load Shape**	Typ. Yr. S-2002; W-2004	Typ. Yr. S-2002; W-2004	07 yrs.; 2007-2013; Risk-based weighted load shapes	Typical Year 2005 for North/Central; 2006 for South	Typical year 2002	Peak (2008)	8 historical years (2012–2019)	40 weather years 1980–2019	2004–2014
	External Load Shape	Typ. Yr. S-2002; W-2004	Typ. Yr. S-2002; W-2004	2007–2013 using ProbA data sheets and PJM model	N/A	Typical year 2002	None	No External Areas represented	40 weather years 1980 to 2019	N/A
	Adjustment to Forecast	Monthly Peak and Energy	Monthly Peak	Seasonal Peaks	Monthly Peaks	Monthly Peak and Energy	Monthly Peaks and Energy	Annual Peak	Annual Peak	N/A
Load Forecast Uncertainty	**Modeling**	7-step Discrete Distribution	7-step Discrete Distribution. Monthly	Weather: 7 years	7 discrete steps normally distributed capturing weather and economic uncertainty	7-step Discrete Normal Distribution, weather	Normal Distribution	7 discrete steps all steps at or above a 50/50 forecast	40 weather years x 5 load forecast uncertainty multipliers = 200 load scenarios	3% to 97% probability distribution

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	90th %ile (% above 50/50 peak)	Varies by Area; asymmetrical	2022-6%; 2024-6%	7.56% at 90%ile (1.28 Standard Deviation)	5.11%	2018-3.9% 2020-5.2%	2020-2.6%; 2018-2.6%	+5% at 99%ile	+2.1% at 90%ile	Varies by Region
	Uncertainties Considered	weather, economic, forecast	Weather, Forecast	Weather Forecast	Weather and Economic	Weather, economic, forecast	Weather, Economic	Weather, economic, forecast	Weather, Economic Forecast Error	Weather and Economic Variability
Behind-the-Meter	**Percentage of Peak Load at Peak**	Unknown	2022-1.9%; 2024-2.6%; Solar only	Minimal; ~1%	N/A	N/A	0	Minimal; Less than 1%	Resource	N/A
	Thermal Generation	Resource	Netted From Load	Within the load	Resource	N/A	N/A	Mix; Resource and Netted from Load	Resource	N/A
	Variable Generation	Resource	Netted From Load	Within the load	Resource	N/A	N/A	Netted from Load	Resource	N/A
	Demand Management	Resource	Netted From Load	Within the load	Resource	NA	N/A	Netted from Load	Resource	N/A
Demand-Side	**Modeling**	Dispatchable resource, Operating procedure (varies by area)	Operating procedure	Operating Procedure	Energy-Limited Resource	Load Modifier	DSM adjusted Load Forecast	Dispatchable Resource	Dispatchable Resource	N/A

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Load Shape / Derates /FOR	N/A	N/A	Flat Seasonal	Count and Duration Limited	Reduction in Peak	None	None	Operation Count Limited	N/A
	Correlation to Load	When modeled as EOP (varies by area)	Not modeled	Not Modeled	not explicitly modeled	NA	None	Not Modeled	Dispatched based on shadow price	N/A
Variable Generation-Wind	**Modeling**	Resource, Fixed resource	Resource	Load Modifier	Load Modifier	Resource	Load Modifier	Resource	Resource	Energy Limited Resource
	Load Shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Monthly	Modeled at capacity credit value	NA	Weekly	Hourly Shape	Hourly Shape for 40 years matching load profile	Hourly Shape
	Correlation to Load	Consistent with load, Not modeled	Not Modeled	Flat	Not Modeled	Consistent with load	Not Modeled	Consistent with load	Match load	N/A
	Capacity Value	0% to 35% (varies by area)	13%	~11%	By wind farm. MISO System Capacity Credit is 15.6%	20% winter and 16% summer	20% Win 10% Sum	Ranges from 10% to 30% for Summer Peak depending on historical year and resource location	63% for coastal wind, 29% for panhandle wind, and 16% for other wind	Varies by Region
Variable Generation-Solar	**Modeling**	Resource	Resource	Load Modifier	Load Modifier	None	None	Resource	Resource with hourly profiles	Energy Limited Resource
	Load Shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Monthly	Modeled at capacity credit value	NA	N/A	Hourly Shape	Hourly for 40 years matching load profile	Hourly Shape
	Correlation to Load	Consistent with load, Not modeled	Not Modeled	Flat	Not Modeled	NA	N/A	Consistent with load	Yes, same weather	N/A
	Capacity Value	Not specified	0% Winter; 38% Summer	94%	MISO System Capacity Credit is 50%	NA	N/A	Ranges from 80% to 100% for Summer Peak depending on historical year	76% for Summer Peak	Varies by Region

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
Hydro-Electric Generation	**Modeling**	Energy Limited Res., Dispatched after Thermal	Resource	Energy Limited Resource, Dispatched after Thermal to reduce LOLE	Resource unless Run-Of-River. Run-of-River submit 3 years of historical data at peak	Energy Limited Resource	Energy Limited Resource, Peak Shaving	Energy Limited Peak Shaving Component	Energy Limited Peak Shaving Component and Emergency Component	Energy Limited Resource
	Energy Limits	Average	N/A	Average 10 years monthly output	Summer Months, Peak Hours 14–17 HE	Different below average water conditions including extreme drought	Median	8 years of historical hydro conditions were modeled 2012–2019	40 years of historical hydro conditions were modeled for 1980–2019	Hourly Shape
	Capacity Derates	Monthly	Monthly	Monthly	At Firm Capacity	Monthly	Monthly	Monthly	Monthly values	N/A
	Planned Outages	Model schedule, Within Capacity Derates	Model scheduled	Model scheduled	Model Scheduled	Not modeled	First five years are scheduled maintenance. Remaining is scheduled by program.	Model scheduled	Netted out based on modeling actual monthly hydro energies	Varies by Region
	Forced Outages	Monte Carlo, Not modeled (varies by area)	Monte Carlo	Not Modeled	Monte Carlo, Run-of-River has none	N/A	Not Modeled	Within Capacity Derates	N/A	N/A
Thermal Generation	**Modeling**	MC; 2 state - some areas up to 7-state	MC; 2-state	MC; 2-state	MC; 2-state	MC 2-state	MC up to 5-state	MC; Up to n-state	MC; 50 iterations of annual simulations with unique forced outage draws performed for each weather year and load forecast error	2-State 3–97% Probability Distribution
	Energy Limits	None	None	None	None explicitly	None	None	None	None	None

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Capacity Derates	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly, Monthly derates inputted into the model	Weekly	Used a summer capacity and a winter capacity value for each unit	Seasonal
	Planned Outages	By model, External Input	By Model	By Model	By Model	By Model	By Model and Manual Input	By Model	By Model calibrated to total historical planned outages	By Model
	Forced Outages	EFORd	5-year EEFORd	EFORd	5-year unit specific EFORd	EFORd	5-year historical average	5-year EFOR GADS Data	5-year EFOR GADS Data; Historical Events Modeled Discretely	Historical 12-year EFOR
Firm Capacity Transfers	**Modeling**	Explicitly Modeled	Explicitly Modeled	Explicitly Modeled	Imports treated as Resource; Exports derated from monthly unit capacities	Imports treated as resource; Exports added as load	Import treated as load modifier	Explicitly Modeled	Not Modeled. All firm resources are modeled inside the ERCOT zone.	Explicitly Modeled
Firm Capacity Transfers	**Hourly Shape Issues**	None	None	N/A	None	Weekly capacities	Hourly Load modification for a typical week.	None	N/A	N/A
Firm Capacity Transfers	**Capacity Adjustments - Transmission Limitations**	None	None	N/A	None	None	N/A	N/A	N/A	N/A

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Transmission Limit Impact of Firm Transfers	Impact derived within model	Endogenously modeled	Limits adjusted	None	Accounted for in interface limits	N/A	N/A	N/A	N/A
	Forced Outages	N/A	No	No	5-year unit specific EFORd	No	No	No	N/A	N/A
Internal Representation	**Assessment Areas**	5	1	7	1	1	1	1	1	6
	Total Nodes	56	5	7	10	1	1	6	1	49
	Node Definition	Determined by potentially limiting transmission interfaces	Market-Defined Regions	Assessment Areas = Nodes	Local Resource Zone	N/A	N/A	Determined by potentially limiting transmission interfaces	N/A	Balancing Authority
	Transmission Flow Modeling in ProbA Model	Transportation /Pipeline	Transportation/Pipeline	AC/DC in PSSE, Transportation/ Pipeline in MARS	Transfer Analysis Import/Export Limit for each Local Resource Zone	Transportation/ Pipeline	N/A	Transportation/Pipe and Bubble; Transmission Limits modeled between nodes	N/A	Transportation/Pipeline
	Transmission Limit Ratings	NY and Maritimes: short-term emergency; all others normal	Short-term Emergency	normal and short-term emergency ratings	N/A	Normal	N/A	Long-Term Emergency	N/A	Normal
	Transmission Uncertainty	Selected Lines	No	No	No	No	N/A	No	N/A	No
External	**Number of Connected Areas**	3	4	4	7	1	3	5	3	0

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	# External Areas in Study	8	4	4	7	1	0	0	SPP; MISO LRZ 8,9,10; Mexico	0
	Total External Nodes	8	59	4	1	1	N/A	N/A	3	0
	Modeling	Detailed	Detailed and At planning reserve margin	Detailed	Less Detailed	Detailed at their Planning Reserve Margin	N/A	No external assistance above firm contracts and transmission service reservation	Detailed at their Planning Reserve Margin	0
Other Demands	**Operating Reserve**	Yes	Yes	No	No	Not Considered	Yes	Yes	Yes, regulation, spin and non-spin reserve requirements modeled. Firm load shed to maintain 1150 MW of operating reserves.	No
Operating Procedures (pre-LOL)	**Forgo Operating Reserve**	OR to 0 in all Areas except Québec and New England.	Fully	Partially or Fully, depending on input from Assessment Area	N/A	N/A	Fully	Fully	Partially	Fully
	Other	DR, public appeals, voltage reductions	DR, 30-min reserves, voltage reduction, 10-min reserves, public appeals	CPP; DCLM;	None	None	DR, Emergency	None	DR and Emergency Thermal Generation from Conventional Generators	None

Appendix D: ProbA Data Forms

The forms used for the 2020 ProbA can be found on the NERC PAWG webpage, located at the following link:
https://www.nerc.com/comm/PC/Pages/Probabilistic-Assessment-Working-Group-(PAWG).aspx

Appendix E: Additional Assessments by Regional Entity or Assessment Area

This informational Appendix serves as a list of references for more detailed information on assessments or assessment methods used by REs or assessment areas.

NERC Webpage:
www.nerc.com
The NERC webpage contains valuable information regarding its mission. For information on its assessments, see the Reliability Assessment and Performance Analysis page. It also contains valuable information regarding the statistics for assessing BES reliability.

NPCC:
https://www.npcc.org/content/docs/public/library/resource-adequacy/2020/2020-12-01-nerc-ras-probabilistic-assessment-npcc-region.pdf
NPCC publishes a report that contains a more detailed look at the multi-area probabilistic reliability assessment for the NPCC Region, referenced in the NERC ProbA and this year's regional risk scenario.

SERC:
serc1.org.
SERC publishes many different assessments that can be found in the link to their main webpage above. Use the contact information in Appendix A for any questions.

WECC:
WECC's WARA Part 1.
WECC performed a separate assessment that contains more details on how the possible coal retirements in their region were selected and can affect their system's reliability.

WECC is also working on developing a portion of their webpage to provide educational materials on how they perform their ProbAs and will work as a great educational material upon its completion.

MISO:
https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf
MISO performs a Loss of Load Expectation study on an annual basis as part of their Resource Adequacy construct.