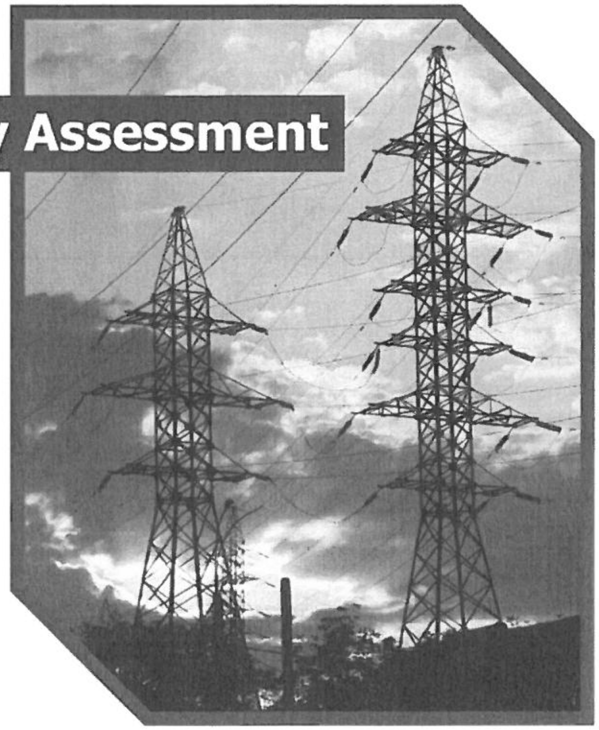
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2017 Long-Term Reliability Assessment



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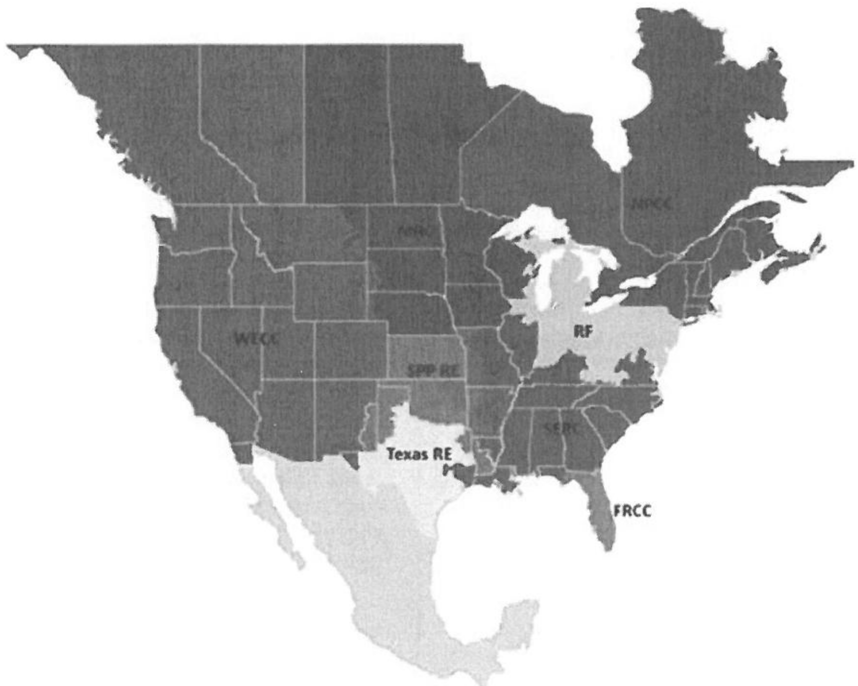
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people. The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map below. To see a map of the 21 assessment area boundaries, see the **Assessment Area Dashboards and Summaries** section.



About This Assessment

This 2017 Long-Term Reliability Assessment (2017 LTRA) was developed by NERC in accordance with the Energy Policy Act of 2005 (Title 18, § 39.11[1] of the Code of Federal Regulations.[2,3] This assessment also fulfils the ERO's Rules of Procedure, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

2017 Format Update

In response to feedback from NERC's Board of Trustees and other NERC stakeholders, the 2017 LTRA is presented in a more succinct format to highlight data and information that is especially impactful to the long-term outlook of the North American BPS. This transition to a shorter format was executed without impacting the comprehensive assessment development process described in the Data Concepts and Assumptions section. Interested parties should contact NERC Staff with any questions.

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

[2] This is also referred to as Section 215 of the Federal Power Act in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the BPS in North America.

[3] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005. The NERC Rules of Procedure, Section 800, further detail the objectives, scope, data and information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[4] BPS reliability does not include the reliability of the lower-voltage distribution systems, which systems use to account for 80 percent of all electricity supply interruptions to end-use customers.

Development Process

This assessment was developed based on data and narrative information collected by NERC from the eight Regional Entities on an assessment area basis to independently assess the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the 10-year assessment period.[5] The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Planning Committee, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the NERC Planning Committee and the NERC Board of Trustees, who subsequently accepted the report and endorsed the key findings.

Data Considerations

Projections in the 2017 LTRA are not predictions of what will happen; they are based on information supplied in July 2017 with updates incorporated prior to publication. The assessment period for the 2017 LTRA is from 2018–2027; however, some figures and tables examine data and information for year 2017. The assessment was developed using a consistent approach for projecting future resource adequacy through the application of NERC's assumptions and assessment methods. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities, which is further explained in the Data Concepts and Assumptions section.

Reliability impacts related to physical and cybersecurity risks are not addressed in this assessment, which is primarily focused on resource adequacy. NERC leads a multi-faceted approach through the Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address these risks, including exercises and information-sharing efforts with the electric industry.

[5] Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Resources refer to a combination of electricity-generating and transmission facilities that produce and deliver electricity and demand-response programs that reduce customer demand for electricity. Adequacy requires System Operators and planners to account for scheduled and reasonably expected unscheduled outages of equipment while maintaining a constant balance between supply and demand.

Executive Summary

The electricity sector is undergoing significant and rapid change that presents new challenges for reliability. With appropriate insight, careful planning, and continued support, the electricity sector will continue to navigate the associated challenges in a manner that maintains reliability and resilience. As NERC has identified in recent assessments, retirements of conventional generation and the rapid addition of variable resources (e.g., wind and solar) are altering the operating characteristics of the grid. A significant influx of natural gas generation raises unique considerations regarding risks related to fuel assurance. While related risks and corresponding mitigations are unique to each area, industry stakeholders and policymakers should continue to respond with policies and plans to address fuel availability. This 2017 LTRA serves as a comprehensive, reliability-focused perspective on the 10-year outlook for the North American BPS and identifies potential risks to inform industry planners and operators, regulators, and policy makers. Based on data and information collected for this 2017 LTRA, NERC has independently identified the following four key findings:

Key Findings

Recent retirement announcements in Texas RE-ERCOT and the canceled nuclear plant expansion in SERC-E result in projected margin shortfalls for both **assessment areas:**

- SERC-E Anticipated and Prospective Reserve Margins drop below the Reference Margin Level beginning in Summer 2020.
- Recently announced plant retirements that were approved by ERCOT result in Anticipated Reserve Margins dropping below the Reference Margin Level beginning Summer 2018; Prospective Reserve Margins remain adequate.
- Other assessment areas project sufficient Anticipated Reserve Margins through 2022.

Amid slower demand growth, conventional generation continues to retire with rapid additions of natural gas, wind, and solar resources:

- NERC-wide electricity peak demand and energy growth are at the lowest rates on record with declining demand projected in three areas.
- Conventional generation retirements have outpaced conventional generation additions with continued additions of wind and solar.
- Retirement plans have been announced for 14 nuclear units, totaling 10.5 GW.
- Natural-gas-fired capacity has increased to 442 GW from 280 GW in 2009 with an additional 44.6 GW planned during the next decade.
- Wind generation currently accounts for more than 10 percent of total installed capacity in six areas with 14.8 GW (nameplate) of NERC-wide additions projected during the next decade.
- A total of 37 GW (nameplate) of solar additions are projected by 2022. Of these, 20 GW (nameplate) are distributed, raising visibility concerns for system planners.

The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services and fuel assurance:

- Operating procedures that recognize potential inertia constraints were recently established in ERCOT and Québec.
- With continued rapid growth of distributed solar, CAISO's three-hour ramping needs have reached 13 GW, exceeding earlier projections and reinforcing the need to access more flexible resources.
- Reference Margin Levels vary across North America depending on the resource mix.
- Methods for determining the on-peak availability of wind and solar are improving with growing performance data.
- Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural gas.

A total of 6,200 miles of transmission additions are planned to maintain reliability and meet policy objectives:

- Despite low or flat load growth, a total of 6,200 circuit miles of new transmission is planned throughout the assessment period with more than 1,100 circuit miles currently under construction.
- Actual transmission additions have increased despite lower projected energy growth.

Recommendations

NERC continually assesses the future reliability of the BPS by evaluating long-term plans and identifying risks. Based on the identified key findings, NERC has formulated the following recommendations:

Policy Makers and Regulators:

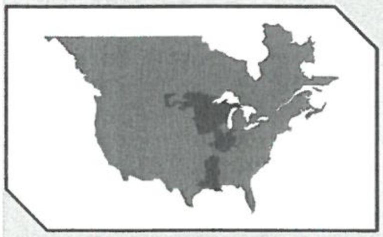
- **Support essential reliability services:** FERC should support new market products and/or changes to market rules that support the provision of essential reliability services, which includes frequency response and increased system flexibility.
- **Recognize time needed to maintain reliability:** State, federal, and provincial regulators should continue to recognize lead times for the generation, transmission, and natural gas infrastructure needed to maintain reliability as industry strives to meet policy goals and initiatives. Reliable operation of the BPS requires dependable capacity with fuel assurance to address consumer needs, impacts of extreme weather conditions, and sudden disturbances on the system.
- **Consider industry study recommendations when reviewing infrastructure requirements:** Regulators (including DOE and FERC) should consider results and conclusions of industry studies that evaluate the impact of natural gas disruptions to the BPS when evaluating infrastructure requirements.
- **Focus on reliability and resilience attributes to limit exposure to risk:** Regulators should consider the reliability and resilience attributes provided by generation to ensure that the generation resource mix continues evolving in a manner that maintains a reliable and resilient BPS.

Industry:

- **Support technologies that contribute to essential reliability services:** All new resources should have the capability to support voltage and frequency. Various technologies can contribute to essential reliability services, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.
- **Integrate DERs with increased visibility:** In areas with expected growth in DERs, system operators and planners should gather data about the aggregate technical specifications of DERs connected to local distribution grids to ensure accurate system planning models, coordinated system protection, and real-time situation awareness.
- **Report on expected reliability concerns:** In areas impacted by an increasing share of natural-gas-fired generation, transmission planners and operators should identify and report on expected reliability concerns due to a large share of interruptible natural gas transportation and supplies. Where deregulated markets exist, market operators should develop additional rues or incentives to encourage increased fuel security, particularly during winter months.

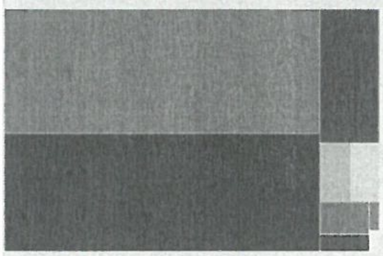
NERC:

- **Conduct comprehensive evaluation of Reliability Standards:** NERC should conduct a comprehensive evaluation of its Reliability Standards to ensure compatibility with nonsynchronous and distributed resources as well as for completeness related to essential reliability services, generator performance, system protection and control, and balancing functions.
- **Monitor reserve margin short falls:** In light of the projected reserve margin shortfalls in TRE-ERCOT and SERC-E, NERC and the respective Regional Entities should identify and assess updated industry plans and proactive measures for maintaining reliability given the reduction in expected capacity resources. NERC and the Regions should determine the likelihood of a capacity shortage in these areas, evaluate the measures being taken, and identify updated plans in the 2018 Summer Reliability Assessment. Longer-term challenges will be evaluated in the 2018 LTRA.



MISO

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

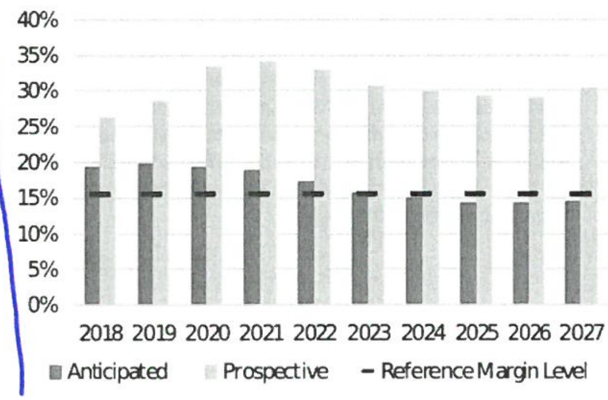


Highlights

- For 2018, MISO is projected to have 2.7 GW to 4.8 GW resources in excess of the regional requirement. Through 2022, regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements.
- Continued focus on load growth variations and generation retirements will allow transparency around future resource adequacy risk.

Demand, Resources, and Reserve Margins										
Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	125,568	126,544	127,022	127,646	128,287	128,897	129,409	129,109	128,913	128,716
Demand Response	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621
Net Internal Demand	119,947	120,923	121,402	122,025	122,666	123,276	123,789	123,488	123,292	123,095
Resources (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Anticipated	143,012	144,857	144,925	145,121	143,866	142,477	142,265	141,079	140,922	141,021
Prospective	151,344	155,322	161,883	163,567	163,093	160,946	160,735	159,548	158,981	160,372
Reserve Margins (%)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Anticipated	19.23	19.79	19.38	18.93	17.28	15.57	14.93	14.24	14.30	14.56
Prospective	26.18	28.45	33.35	34.04	32.96	30.56	29.85	29.20	28.95	30.28
Reference Margin Level	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80

Existing On-Peak Generation (Summer)		
Generation Type	Peak Season Capacity	
	MW	Percent
Biomass	439	0.3
Coal	56,226	40.9
Hydro	1,271	0.9
Natural Gas	59,546	43.3
Nuclear	11,955	8.7
Petroleum	2,427	1.8
Pumped Storage	2,775	2.0
Solar	319	0.2
Wind	2,431	1.8



Planning Reserve Margins

Planning Reserve Margins

The Anticipated Reserve Margin remains above the Reference Margin Level of 15.8 percent through the summer of 2022. In 2018, MISO is projected to have 2.7 GW to 4.8 GW of resources in excess of the Planning Reserve Margin Requirement. MISO's regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements in the 2019–2022 time frame.

Demand

MISO projects the summer coincident peak demand to grow at an average annual rate of 0.3 percent for the 10-year period, slightly less than the 2016 LTRA. Zones 4 and 7 (Lower Peninsula Michigan) have essentially flat load growth rate over the 10-year period; specifically, Zone 4 saw the largest year-over-year change within MISO. This included forecasted load reductions due to expected loss of industrial load paired with a near-flat future growth rate. These are the main drivers in the reduction of regional growth.

Demand-Side Management

MISO forecasts 5,620 MW of direct control load management and interruptible load to be available for the assessment period. MISO also forecasts at least 4,129 MW of behind-the-meter generation to be available for the assessment period. Zone 4 and Zone 7 had a significant increase in DR for the assessment period, due to new registrations by aggregators in MISO's Module E Capacity Tracking Tool. Energy efficiency is not explicitly forecasted at MISO; any energy efficiency programs are reflected within the demand and energy forecasts.

Distributed Energy Resources (DERs)

As part of the MISO Transmission Expansion Plan (MTEP) study, there was an attempt to collect information on DERs. The forecast provides an estimate of DER programs and their impact on peak demand and annual energy savings. This forecast positions MISO to understand emerging technologies and the role they play in transmission planning as there is a specific case on distributed energy resources both at a base case level and increased penetration level. MISO has not experienced any operational challenges as of yet but expects to as programs grow in the future.

Generation

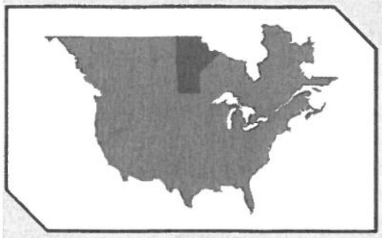
A total of 574 MW of generation capacity is retiring in 2017 and an additional 735 MW of generation capacity will retire in 2018. Through the generator interconnection queue (GIQ) process, MISO anticipates 4,517 MW of future firm capacity additions and uprates along with 4,106 MW of future potential capacity additions to be in-service and expected on-peak during the assessment period. This is based on a snapshot of the GIQ and the 2017 OMS-MISO Survey as of June 2017, which includes the aggregation of active projects.

Capacity Transfers

The SPP settlement agreement has put in place a regional directional transfer limit replacing the Operations Reliability Coordination Agreement operating limit. Specifically, midwest (LRZs 1-7) to south (LRZs 8-10) flow is limited to 3,000 MWs and south to midwest is limited to 2,500 MWs. Without this regional directional transfer limit, there is roughly 3 GW in the near term that would be available to support resource adequacy in the short-term.

Transmission

The annual MISO Transmission Expansion Plan (MTEP) proposes transmission projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in MISO. Major categories of the MTEP include the following: A total of 106 baseline reliability projects required to meet NERC Reliability Standards, 32 generator interconnection projects required to reliably connect new generation to the transmission grid, 1 market efficiency project to meet requirements for reducing market congestion, 1 transmission delivery service project that includes network upgrades driven by transmission service requests, and 243 other projects.



MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to 556,000 customers throughout Manitoba and natural gas service to 272,000 customers in various communities throughout southern Manitoba. The Province of Manitoba is 250,946 square miles. Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Highlights

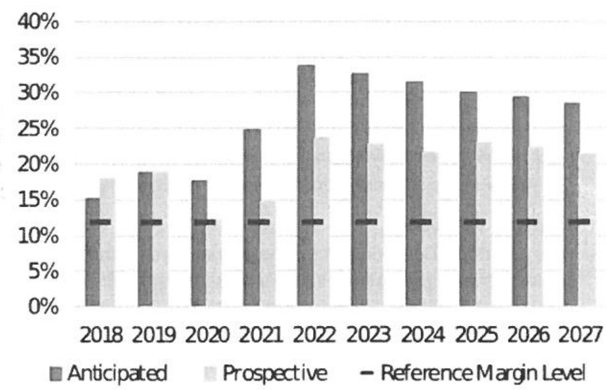
- The Anticipated Reserve Margin does not fall below the Reference Margin Level of 12 percent in any year during the assessment period. The 630 MW (net addition) Keeyask hydro station is expected to come into service beginning in the winter of 2021/2022, which helps ensure resource adequacy in the latter half and after the end of the current assessment period. No resource adequacy issues are expected.
- Demand is flattening over the LTRA horizon as a result of reduced load growth and energy efficiency and conservation efforts.
- The Bipole 3 HVDC transmission line is expected to come into service in 2018 and will improve reliability during extreme events.

Demand, Resources, and Reserve Margins

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	4,760	4,642	4,681	4,706	4,739	4,777	4,817	4,840	4,867	4,897
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,760	4,642	4,681	4,706	4,739	4,777	4,817	4,840	4,867	4,897
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	5,488	5,513	5,507	5,870	6,338	6,338	6,338	6,298	6,298	6,298
Prospective	5,609	5,517	5,257	5,395	5,863	5,863	5,863	5,948	5,948	5,948
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	15.29	18.76	17.65	24.73	33.74	32.68	31.58	30.13	29.40	28.61
Prospective	17.85	18.85	12.30	14.64	23.72	22.73	21.71	22.89	22.21	21.46
Reference Margin Level	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00

Existing On-Peak Generation (Winter)

Generation Type	Peak Season Capacity	
	MW	%
Coal	92	1.7
Hydro	5,095	91.8
Natural Gas	311	5.6
Wind	52	0.9



Planning Reserve Margins (Winter)

Planning Reserve Margins

The Anticipated Reserve Margin does not fall below the Reference Margin Level of 12 percent in any year during the 10-year assessment period.

Demand

The province is divided into five smaller subregions: Northern, Western, Interlake, Eastern and Winnipeg. The localized winter peak growth rate varies from a low of 0.5 percent in the Northern region to a high of 4.4 percent in the Eastern region. The high growth in the Eastern region is due to population growth in the Steinbach area as well accelerated growth on the east side of Lake Winnipeg.

Demand-Side Management

Manitoba Hydro does not have any demand side management resources that are considered as controllable and dispatchable demand response.

Distributed Energy Resources (DERs)

Manitoba Hydro projects that installed DERs will increase from 15.5 MW in 2017 to 30.8 MW in 2027. There is less than 1 MW of solar distributed energy resources in Manitoba. Even with high growth rates, Manitoba Hydro is not anticipating the quantity of solar distributed energy resources to increase to a level that could cause operational impacts during the assessment period.

GeneraƟon

The 630 MW (net addition) Keeyask hydro station is anticipated to come into service beginning in the winter of 2021/2022, which will help promote resource adequacy in the latter years of the assessment period and support a related 250 MW capacity transfer into MISO. The only unit currently impacted by environmental requirements is Brandon Unit 5 (coal), which is categorized as an unconfirmed retirement at the end of 2019. The driver of the potential retirement of Brandon Unit 5 is both environmental and end of lifespan. No adverse effect on reliability is anticipated as a result of the potential retirement as this unit is currently planned to be converted into a synchronous condenser for area voltage support once the coal-fired boiler is retired.

Capacity Transfers

The Manitoba Hydro system is interconnected to the MISO Zone 1 Local Resource zone (which includes Minnesota and North Dakota), which is summer-peaking as a whole. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only if the following conditions simultaneously occur: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. The additional hydro generation and the related 250 MW capacity transfer into the MISO Region will tend to increase north to south flows on the Manitoba-MISO interface. A 100 MW capacity transfer from Manitoba to Saskatchewan will tend to increase east to west flow on the Manitoba-Saskatchewan interface. Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and IESO. In accordance with these agreements, planning and operating related issues are discussed and coordinated through respective committees.

Transmission

There are several transmission projects projected to come on-line during the assessment period. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads, transmit power to the export market, improve safety, improve import capability, increase efficiency, and connect new generation. The major system enhancement projects include the addition of the third bipolar HVdc transmission system to improve reliability, especially during extreme events; these are expected to come into service in 2018. Manitoba Hydro is expecting a new 500 kV interconnection from Dorsey to Iron Range (Duluth, Minnesota) to come into service in 2020. The high growth in the Eastern region is driving the addition of new transmission such as the 115 kV Pine Falls to Manigotagan line and the St. Vital to Letellier 230 kV line. No reliability impacts are anticipated as the localized growth is considered in the subregional transmission planning process. Some transmission projects have been delayed a few years due to lower than expected load growth in the local area. A temporary operating procedure will ensure sufficient generation is on-line in Brandon to support voltages at winter peak, which allows the Dorsey to Portage 230 kV line to be deferred.