NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interregional Transfer Capability Study Canadian Analysis

Strengthening Reliability Through the Energy Transformation

Final Report

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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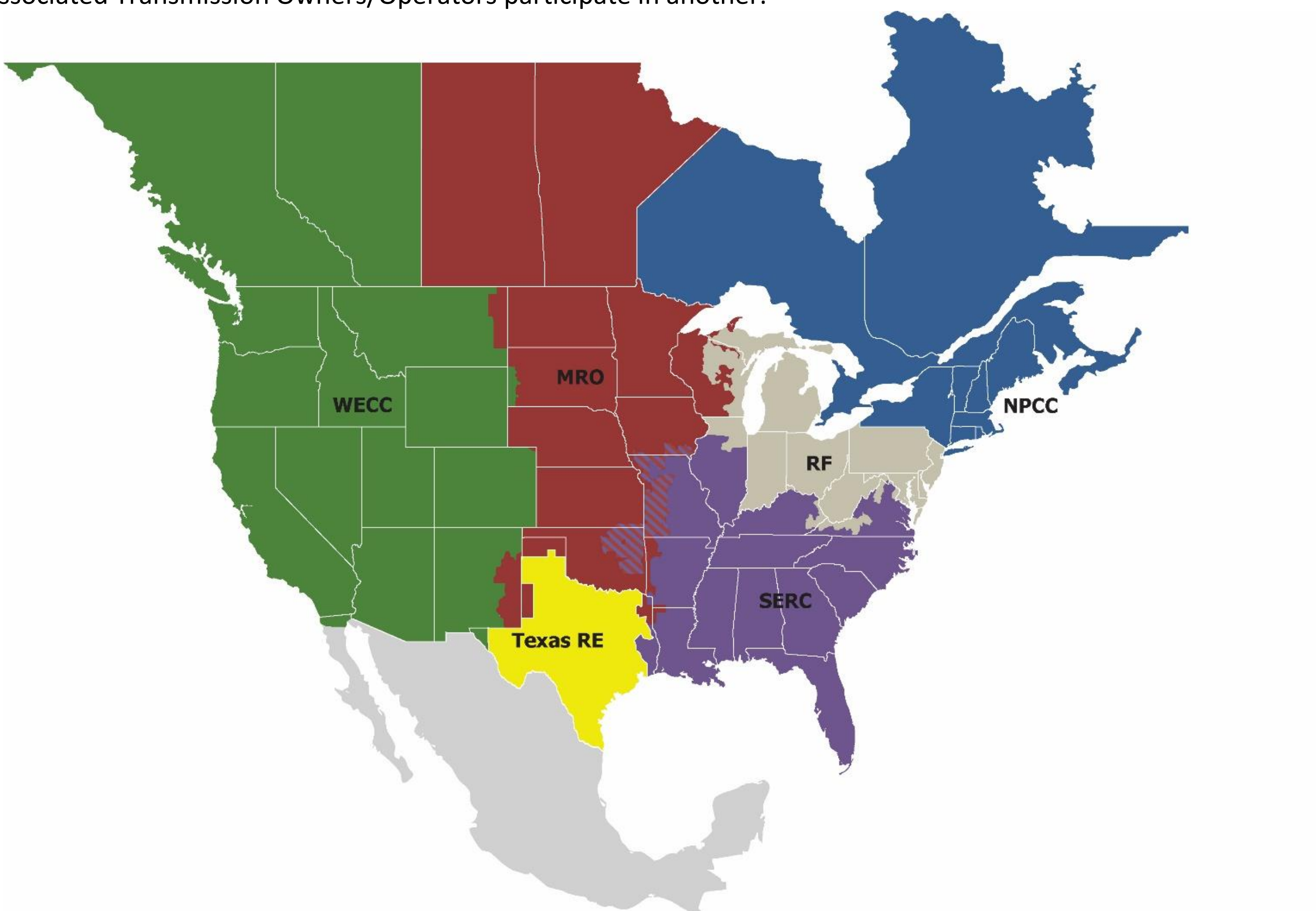
Preface

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 NERC and the six Regional Entities, is a highly reliable, resilient, 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 Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity 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

Statement of Purpose

NERC conducted the Interregional Transfer Capability Study (ITCS) to inform the potential need for more electric transmission transfer capability to enhance reliability in the United States.[1] The ITCS was completed and filed with the Federal Energy Regulatory Commission (FERC) on November 19, 2024,[2] and involved transfer capability calculations between neighboring transmission planning regions within the United States and from Canada to the United States. Additionally, the report identified opportunities to increase transfer capabilities that would be beneficial for reliability between Canada and the United States.

With numerous transmission lines between Canada and the United States, the analysis would be incomplete without a thorough understanding of the Canadian limits and available resources. In NERC technical forum discussions, some Canadian stakeholders requested a similar study of transfer capabilities into and between Canadian provinces as well as identification of potential reliability-enhancing increases to transfer capability consistent with the original ITCS study.

NERC and the six Regional Entities,[3] collectively called the ERO Enterprise, developed and executed the Canadian Analysis in collaboration with industry. This report details the inputs, processes, key findings, and insights of the Canadian Analysis. While there are many similarities between the Canadian and U.S. systems, there are also numerous differences detailed in this report that need to be understood when considering these results.

[1] The ITCS was mandated by the U.S. Congress in June 2023. See H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress

[2] FERC Docket #AD25-4-000

[3] NERC's work with the Regional Entities is governed by Regional Delegation Agreements (RDA) on file with FERC and posted on NERC's website. See also section 215(e)(4).

Executive Summary

The North American grid is a complex machine that has evolved over many decades; it integrates a network of generation, transmission, and distribution systems across vast geographic areas. As a result of the changing resource mix[4] and extreme weather, interregional energy transfers play an increasingly pivotal role. More than ever, a strong, flexible, and resilient transmission system is essential to support energy adequacy[5] to reliably meet customer demand.

Canadian systems play a crucial role in the interconnected North American bulk power system (BPS), so NERC analyzed transfer capability[6] and energy margins to evaluate the reliability benefits of enhancing cross-border and cross-provincial transmission. This analysis complements NERC's Interregional Transfer Capability Study (ITCS) published last year. The conclusions of this Canadian Analysis align with those of the Canada Electricity Advisory Council, which "identified the reinforcement and expansion of inter-regional transmission as a critical measure to support the reliability of Canada's electricity system," a finding that was incorporated into Canada's Clean Electricity Strategy[7] in a recent report.

CANADIAN ANALYSIS

In Scope

- A common modeling approach to study the North American grid independently and transparently
- Evaluation of the impact of extreme weather events on hourly energy adequacy using the calculated current transfer capability and 10-year resource and load futures
- Identifying additional transfer capability that could address energy deficits when surplus is available in neighboring regions
- Extensive consultation and collaboration with industry
- Reliability improvement as the sole consideration in evaluating additional transfer capability

Out of Scope

- Economic, siting, policy, or environmental impacts
- Alternative modeling approaches—these results may differ from other analyses
- Quantified impacts of planned projects
- Endorsement of specific projects, as additional planning by industry would be necessary to determine project feasibility
- Recent changes to load forecasts, renewable targets, or retirement announcements

A Critical Study: Scope and Focus

NERC assessments[8] identified the need for more transmission throughout North America and a strategically planned resource mix[9] to address these changes and support the ongoing electrification of the economy, including the growing transportation sector, industrial loads, and data centers. More frequent extreme weather events may further compound the challenge. In the interest of public health, safety, and security, the need for a reliable energy supply becomes most pronounced under these extreme conditions. These factors emphasize the criticality of adequate and

[4] This phrase relates to the replacement of traditional dispatchable resources with a higher percentage of intermittent resources with non-stored fuel sources, such as wind and solar resources.

[5] While there are many facets to reliability, the Canadian Analysis focuses on energy adequacy (the ability of the bulk power system (BPS) to always meet customer demand).

[6] Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

[7] Powering Canada's Future: A Clean Electricity Strategy - Natural Resources Canada

[8] NERC's assessments can be found at nerc.com.

[9] The terms "resource mix" and "resources" broadly include generators, storage, and demand response.

informed planning at a broad interregional level to support future grid reliability and resilience. A common approach, consistent assumptions, and coordinated results were key elements of the Canadian Analysis.

The Canadian Analysis is the first-of-its-kind assessment of transmission transfer capability and hourly energy margin analysis in Canada under a common set of assumptions but is not a transmission plan or blueprint. Transmission assessments, like the Canadian Analysis, are crucial to understanding potential options to mitigate future risks; however, alternative approaches other than transmission, such as local generation or demand-side solutions, can also mitigate future energy risks. The study results should be considered as an input into subsequent planning discussions that will consider broader objectives and the cost-effectiveness of different alternatives to meet long-term needs.

This study provides insights for further discussion and intentionally has a very focused scope. As a result, the Canadian Analysis specifically does **not** consider the following:

- **Economic and Policy Assessments:** Economic analysis, cost-benefit evaluation, financial modeling, or trade policies, such as tariffs, were not factors in this study. The focus was strictly on improving energy adequacy through incremental transfer capabilities between adjacent transmission planning regions (TPR). Specific policy objectives, such as environmental targets, are only included to the extent that these decisions were factored into the submitted *Long-Term Reliability Assessment* (LTRA) data.
- **Project-Specific Endorsements:** This report highlights areas where new transmission capacity could improve reliability but does not endorse individual transmission projects.
- **Transmission Expansion Analysis:** The analysis is not a replacement for existing or future transmission expansion planning efforts or interconnection studies, nor does it represent a comprehensive transmission plan. Economic and project viability assessments are needed to fully understand cost implications, market impacts, siting and permitting challenges, and further technical considerations.
- **Operational Mitigation:** The analysis used existing interconnection planning models developed annually by NERC and the Regional Entities. The analysis did not evaluate operational mitigations through re-dispatch or other actions.
- **Capacity Expansion Planning:** Transmission needs are heavily influenced by future resource assumptions. Significant changes to the underlying assumptions could impact the energy margin analysis and, consequently, identified transfer capability additions. This study does not reflect the tradeoffs between resources and transmission as a means of meeting future resource adequacy needs.
- **Probabilistic Resource Adequacy Analysis:** while the energy margin assessment was conducted across 12 weather years and more than 100,000 hours of chronological operations, it was not a probabilistic resource adequacy study performed across hundreds of thousands of samples. This study is not intended to replace a region's resource adequacy framework, Planning Reserve Margins, or capacity accreditation.

The Canadian Analysis demonstrates an opportunity to optimize reserve use across multiple TPRs and shows how transmission can maximize the use of resources, including energy-limited storage and demand response. Furthermore, the analysis highlights the ongoing importance of holistic transmission and resource planning, as increasing transfer capability without surplus energy would be inefficient.

How to Use this Report

> **The Canadian Analysis findings are directional, helping stakeholders identify where improvements could be most impactful.**

This report can be used for envisioning and planning the future of a more resilient and reliable grid. While the Canadian Analysis offers valuable insights to explore reliability under extreme conditions, its findings are foundational for further discussions and informing any future regulatory action. While the study highlights specific needs to improve resilience under extreme conditions based on 2023 LTRA data, it indicates a more positive trend under more recent assumptions, particularly in Ontario and Québec. NERC encourages enhanced collaboration between Planning Coordinators, careful alignment with federal and provincial policies, and consistent stakeholder engagement to effectively assess, refine, and execute strategies. Further guidance on how policymakers, planners, and stakeholders can use these results is noted in the ITCS report.[10] Use of this Canadian Analysis report can support collaborative efforts between utilities, planning organizations, and regulators to help inform directional forward-thinking options for potential vulnerabilities.

Enhancing Reliability–Key Canadian Features

The Canadian electric system has some distinct features that make it differ from the rest of the BPS, including regulatory and planning coordination, geography, climate, and other system characteristics.

Regulatory and Planning Coordination

Canadian provinces have their own Planning Coordinators that are responsible for transmission and resource planning within their system.[11] Provincial regulators have jurisdiction over electricity generation, intra-provincial transmission, and distribution matters. Canada's Energy Regulator/Régie de l'énergie du Canada has the authority to make decisions and give orders or directions over electricity exports, international transmission lines, designated inter-provincial transmission lines, and offshore renewable energy in certain northern and offshore areas of Canada.[12] The Canadian Nuclear Safety Commission regulates nuclear generation. The Canadian Analysis is intended to assist Planning Coordinators and regulators as they evaluate future energy risks.

For this study, an advisory group of stakeholders was formed to ensure a comprehensive and inclusive study, including regulators, industry trade groups, and transmitting utilities.

Geography, Climate, and System Characteristics

Most provinces have few major load centers, most of which are near the southern border, with vast and sparsely populated areas further north. Various options must be carefully weighed before deciding to build new transmission lines over long distances. Additionally, due to the northern latitudes, systems in Canada are typically designed to operate in extreme cold weather. However, extreme cold weather conditions over Eastern Canada in February 2023 resulted in impacts to multiple provinces, including demand management and load shed. Likewise, Western Canada was recently impacted by extreme cold weather in January 2024.[13]

Provinces like British Columbia, Manitoba, Ontario, and Québec have abundant hydro resources. Many, but not all, of these hydro resources are backed by multi-year storage capacity, making short-term drought conditions less likely to cause energy shortages. Nevertheless, prolonged drought conditions could have potential negative impacts.

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[10] https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf, executive summary pages xix–xx

[11] For the purposes of this study, New Brunswick also includes Prince Edward Island (PEI) and a small portion of northeast Maine. Impacts from PEI's load levels and stability limitations are considered in the transfer capability assessments.

[12] CER – Provincial and Territorial Energy Profiles – Canada

[13] Alberta electricity system events on January 13 and April 5, 2024: MSA review and recommendations. Note that weather year 2024 was not included in the assessment as full-year data was not available at the time of study.

In many cases, international ties with the United States have higher transfer capability than inter-provincial ties due to physical proximity and/or to gain access to larger markets. As a result of the geographic distances, adverse conditions in one province are less likely to impact neighboring provinces. However, northern states and Canadian provinces with cross-border ties rely on each other for both economic and reliable transfers of energy across borders, particularly during extreme weather events and/or higher-than-normal forced outages.

Transfer Capability Analysis

The transfer capability analysis results are provided beginning in **Chapter 2**. The current transfer capability analysis between each pair of neighboring TPRs focused on two different base cases,[14] representing 2024 Summer and 2024/25 Winter, with results shown in **Figure ES.1** and **Figure ES.2**, respectively. A complete listing of the current total transfer capability (TTC)[15] results is provided in **Chapter 3**. These transfer capabilities represent the ability of the entire network to move energy from one TPR to another TPR, but are not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities. This study did not follow a path-based calculation method used in many TPRs, so the results generally do not match individual facility ratings. Normally open ties, such as those between interconnections, were not considered in this evaluation.

Key Findings–Transfer Analysis

- Transfer capability varies seasonally and under different system conditions that limit transmission loading; it cannot be represented by a single number.
- Transfer capability is highly dependent on coordinated phase angle regulator settings, particularly in Saskatchewan, Manitoba, and Ontario.
- Prince Edward Island load impacts the transfer capability from New Brunswick to Nova Scotia.
- Transfer capability differs across Canada, with total import capability varying between 5% and 80% of peak load.
- Observed transfer capabilities are generally higher between Canada and the United States but relatively lower between provinces.
- The magnitude of transfer capability is not itself a measure of energy adequacy.
- Interregional transfer capability, as studied in this analysis, is not synonymous with path ratings.

[14] Base cases are computer models that simulate the behavior of the electrical system under various conditions. The cases chosen were from readily available seasonal peak load models and updated by industry to reflect future conditions.

[15] TTC is defined as the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

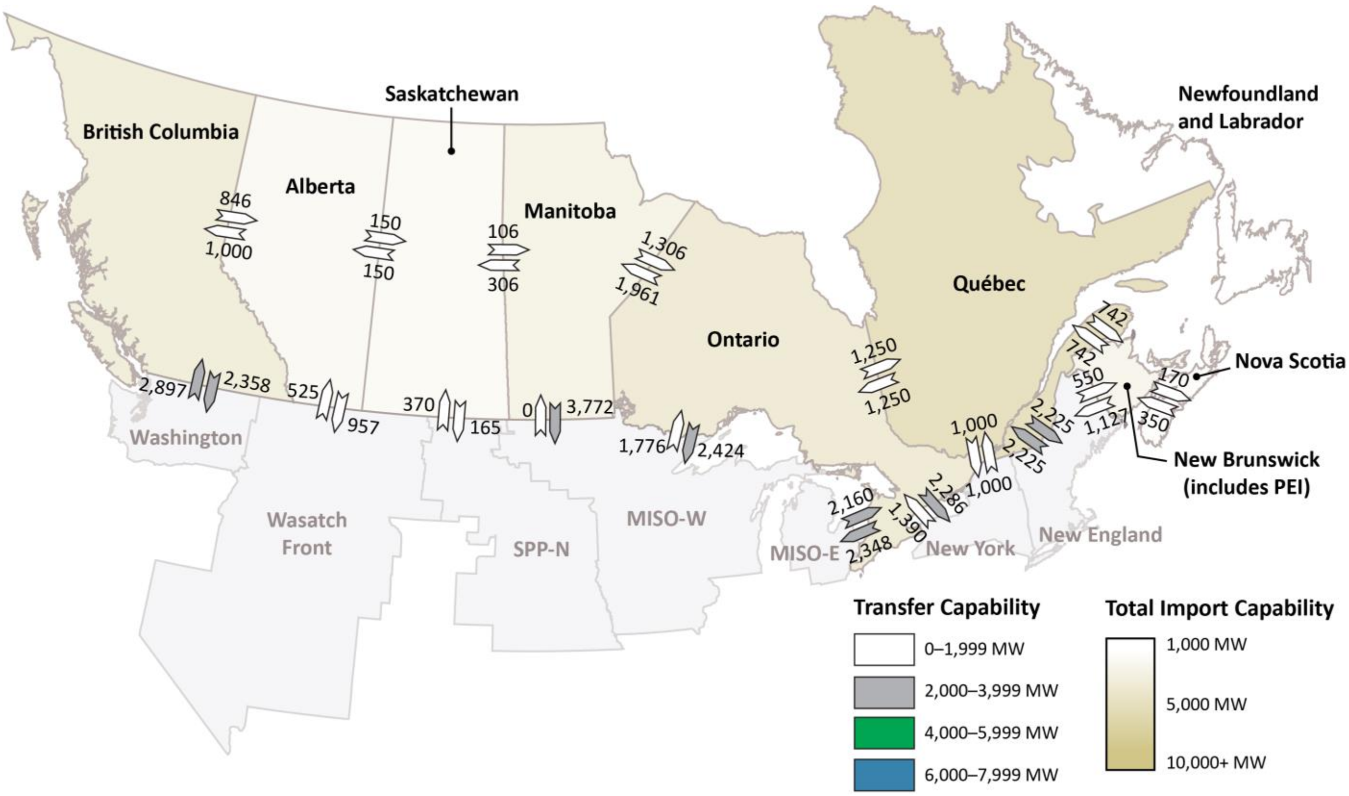

Figure ES.1: Transfer Capabilities (Summer)

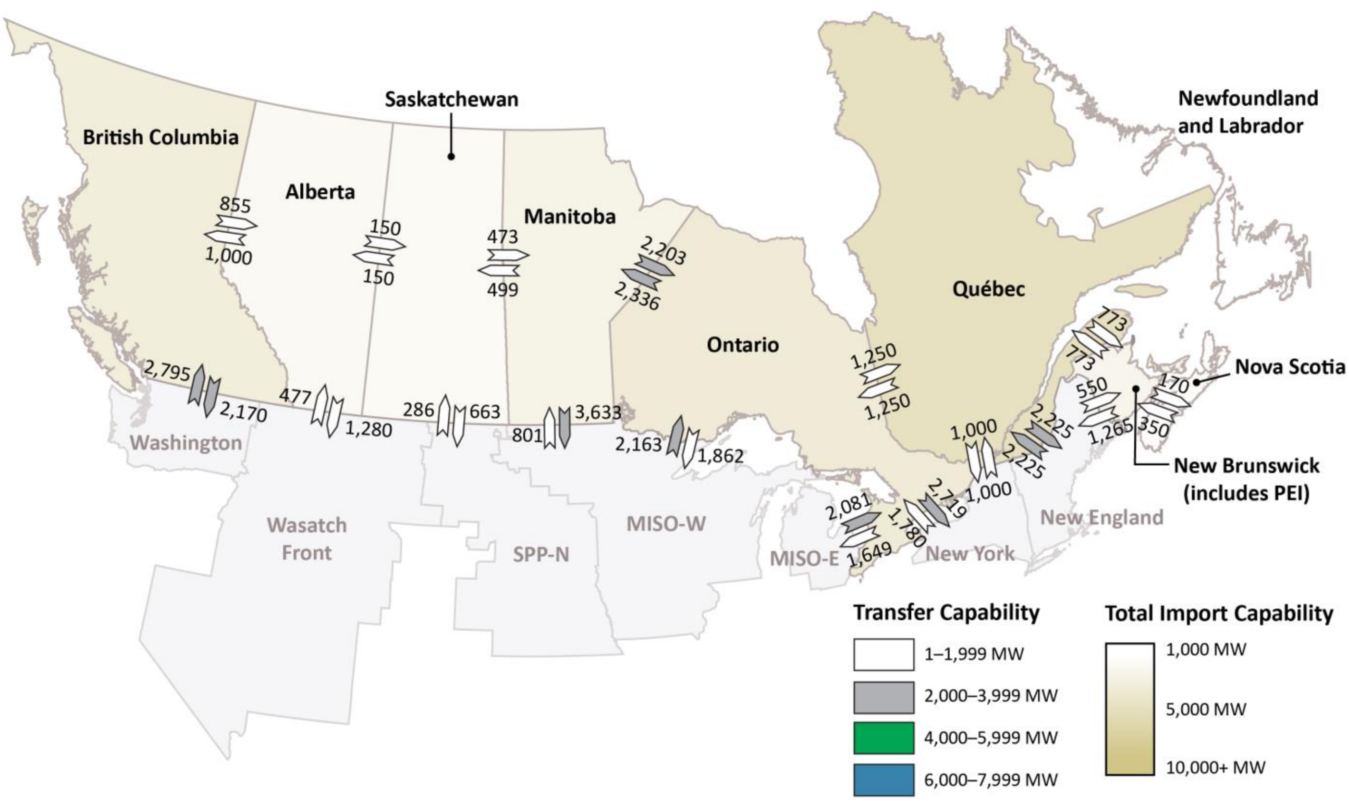

Figure ES.2: Transfer Capabilities (Winter)

The transfer capability results in this report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, which can vary significantly between seasons. For the same reasons, transfer capability can differ during non-peak periods from the peak conditions studied. This study used a set of cases representative of stressed system conditions most relevant for the energy margin analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures, so higher transfer capabilities may be available under conditions different from those studied. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans could also significantly alter the study results.

Transfer Capability Additions to Enhance Reliability

Identified Transfer Capability Additions in the Context of Reliability

This study identified additions to transfer capability that could mitigate potential grid reliability risks under the most challenging conditions. These additions will need further analysis as part of reliability and economic planning. The analysis excludes cost-benefit assessments; no economic or financial modeling was used. In the analysis, transfer capability additions reduce energy deficits by transferring available excess energy from neighboring TPRs.[16]

The Canadian Analysis evaluated the future energy adequacy of the BPS if historical extreme weather conditions occurred again in 2033.[17] Specifically, the study applied 12 past weather years to the 2033 load and resource mix reported in the 2023 LTRA using the current transfer capabilities.[18] The future year (2033) was selected because interregional transmission projects typically require at least 10 years to plan and build, and forecasting demand and resources beyond that time frame becomes increasingly speculative and uncertain.

The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby helping to improve energy adequacy. The six-step process (see **Figure ES.3**) used in this evaluation is described in **Chapter 5**, culminating in a list of suggested transfer capability additions. While there are several factors that transmission planners consider (including reliability, economics, and policy objectives) given NERC's role, the Canadian Analysis focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

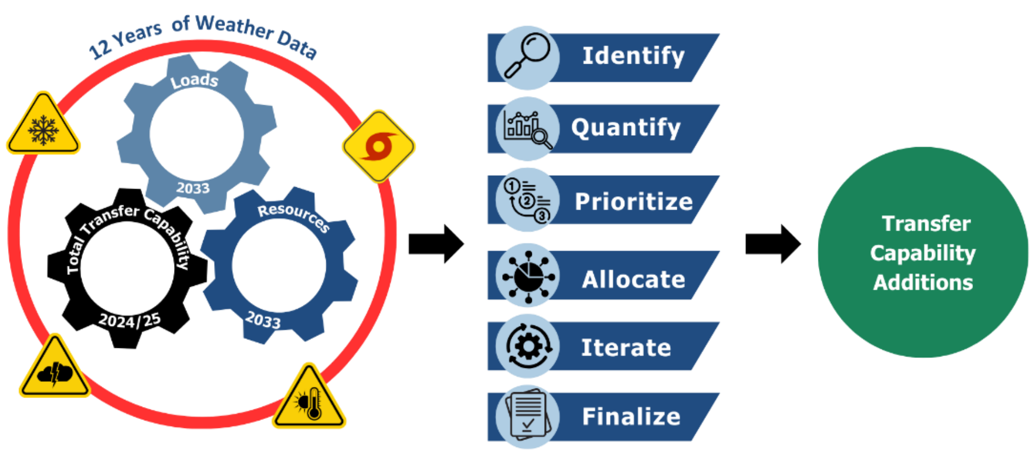

Figure ES.3: Process Overview

[16] Additional details can be found at https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf, executive summary page xiv.

[17] This study did not incorporate climate change models.

[18] The transfer capability analysis calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Identified additions to transfer capability do not account for any changes to the transmission network that are planned after Winter 2024/25.

Key Findings–Energy Margin Analysis (2033)

- Canadian systems were found to be increasingly vulnerable during extreme weather due to anticipated load increases and the changing resource mix. Transmission limitations, and potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional weather conditions. The import capability that could be beneficial during extreme conditions varied significantly across the country. An additional 12–14 GW of transfer capability may be an effective vehicle to strengthen energy adequacy under extreme conditions:
  - Québec faces energy deficits due to projected demand growth, especially during extreme winter conditions, with a maximum deficiency of 10 GW.
  - Nova Scotia faces shortages in all the weather years studied. Expansion of transfer capability with New Brunswick would address these deficits.
  - Energy deficits were also identified in Alberta, Saskatchewan, Ontario, and New Brunswick. There are multiple options that could address these deficiencies via additional transfer capability, including expansion of cross-Interconnection capability, new connections, and upgrades to existing interfaces.
- More recent industry forecasts reflected in 2024 LTRA data generally result in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts. Ongoing studies will capture the impacts of future forecast changes.
- Weather-related outages were not found to be a major contributor to deficiency events, as Canadian systems are generally designed to handle extreme cold conditions. However, high winter peak loads can still challenge the available energy supply.
- Some identified transmission additions could be addressed by projects already in the planning, permitting, or construction phases. Likewise, existing system capability to switch resources or load between provinces, which was not accounted for in this study, may help reduce the identified shortfalls.
- The importance of maintaining sufficient generating resources underpins the study's assumptions. Higher-than-expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability additions if surplus energy is available from neighbors.
- A broad set of solutions should be considered, including transmission, local resources, demand-side, and storage solutions. A diverse and flexible approach allows tailored solutions specific to each province's vulnerabilities, risk tolerance, economics, and policies.

The potential for energy deficiency[19] was identified in all 12 weather years evaluated. The results identified the potential for energy deficiency in six provinces, with a maximum resource deficiency of 10 gigawatts (GW) in Québec based on 2023 LTRA data. Results from the energy margin analysis are provided in **Chapter 6**.

The potential for energy deficiency was identified in all 12 weather years evaluated.

The Canadian Analysis used these results to develop a list of additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. As a result, the analysis identified 14 GW of additional transfer capability that would improve energy adequacy under the studied extreme conditions throughout Canada.[20] **Figure ES.4** shows the existing and potential[21] new interfaces where beneficial additional transfer capability is identified.

14 GW of additional transfer capability could improve energy adequacy under extreme conditions.

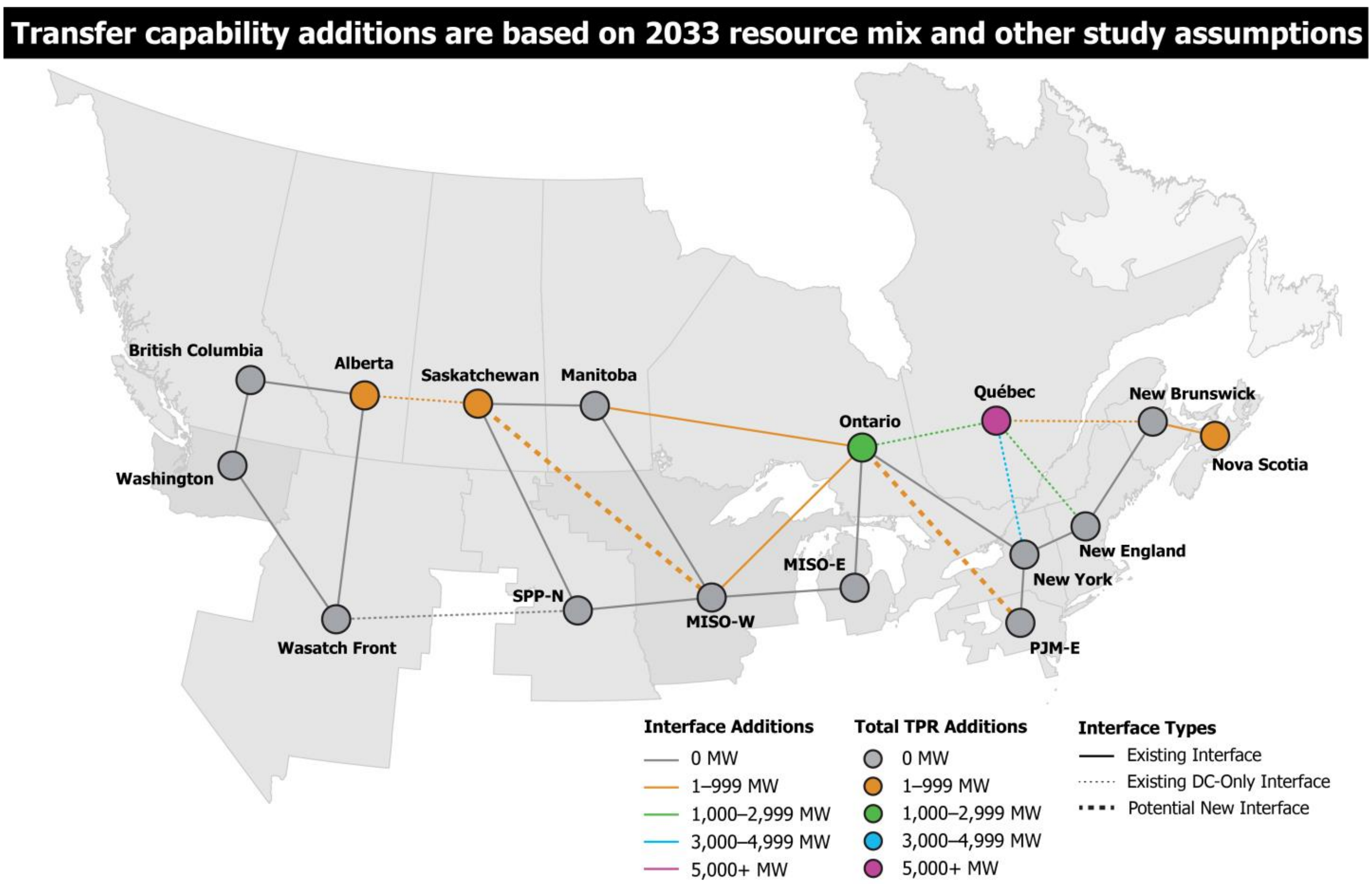

Figure ES.4: Transfer Capability Additions

During extreme cold weather, the Québec system, which has the largest load of all provinces, had the most significant energy deficiency (10 GW) under the studied conditions and the greatest volume of identified transfer capability increases. Specifically, potentially beneficial transfer capability increases into Québec total approximately 10 GW

[19] The terms "resource deficiency" and "energy deficiency" are used interchangeably throughout this report to describe instances where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level.

[20] The Canadian Analysis findings result from NERC working with the Regional Entities and in collaboration with the Advisory Group.

[21] Potential new interfaces evaluated are shown in **Chapter 1**.

between the Ontario, New York, New England, and New Brunswick interfaces. Despite the magnitude of the deficiency, these transfer capability additions address all identified energy deficits. Further details on transfer capability additions are provided in **Chapter 6**.

Two sensitivity studies were also performed as described in **Chapter 7**. More recent forecasts, based on 2024 LTRA data, generally result in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts. The comparison of transfer capability additions for the 2024 LTRA sensitivity are shown in **Figure ES.5**. Ongoing studies will capture the impacts of future forecast changes.

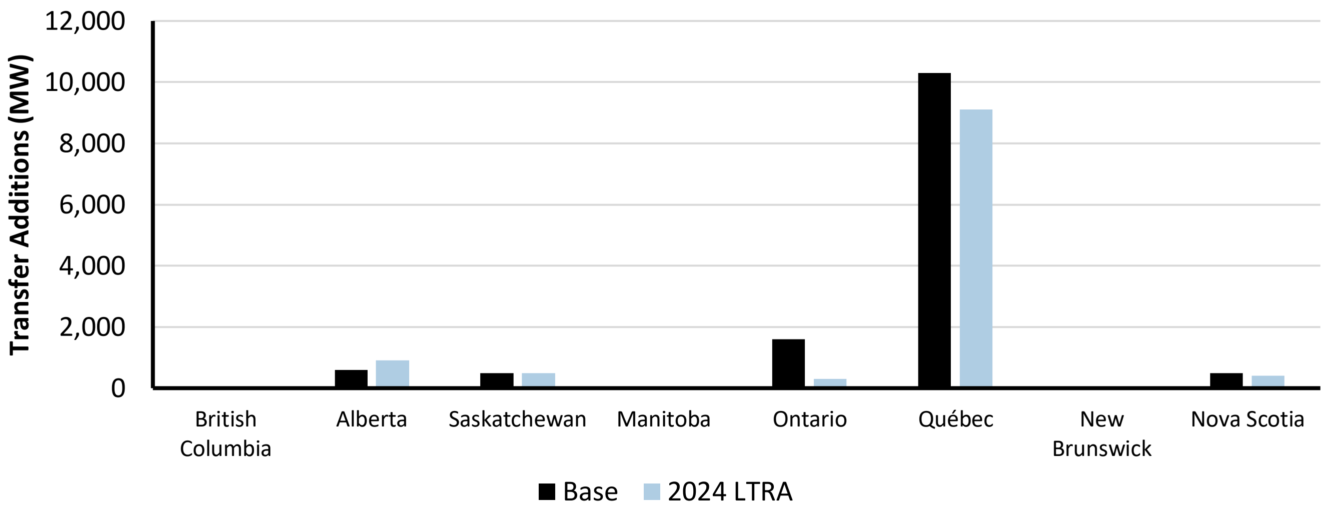

Figure ES.5: Transfer Capability Additions (2024 LTRA Sensitivity)

Future resource and load assumptions are pivotal to ascertain the amount of transfer capability additions that may be beneficial for enhancing reliability. If fewer resources are assumed, many TPRs would exhibit energy deficiencies. This could limit a TPR's ability to support neighbors during, for example, extreme weather events. Conversely, if more resources are assumed, the need for increases to transfer capability is reduced. The specific resource assumptions are provided in **Appendix C**. Resource projections may shift over time with new technologies, market conditions, or policy directives. These dynamics, and changes to load growth forecasts, highlight the need for this type of analysis to be repeated.

Various Options to Address Resource Deficiency Risks

When addressing the identified risks, entities have various tools at their disposal. While the Canadian Analysis identifies additions to transfer capability as one means of addressing extreme condition vulnerabilities, these needs can be addressed in a variety of ways:

- **Internal Resource Development:** Adding internal resources, such as generation or storage, can reduce the need to rely on the transfer of energy from external resources. Importantly, these resources should not be subject to the same common-mode failures as extreme conditions may impact multiple parts of the system simultaneously. For example, adding solar resources may not provide significant reliability benefits if energy deficits are expected in the early morning or evening hours in winter.

Planners have multiple options to mitigate identified energy deficiencies and should consider the impacts of each option.

- **Transmission Enhancements to Neighboring TPRs:** Increasing transfer capability can provide critical access to external energy resources that may not be simultaneously impacted by extreme conditions. Increasing transfer capability requires the elimination of transmission bottlenecks between TPRs and/or within a TPR through transmission reinforcement or grid-enhancing technologies. This approach necessitates the following:
  - **Resource Evaluations:** Each neighboring TPR should be assessed to verify that sufficient, reliable generation resources are available to support the energy transfers needed during the critical periods. Building transfer capability between systems that are simultaneously resource-deficient will not improve energy adequacy during those extreme conditions.
  - **Permitting and Siting Requirements:** Transmission projects require extensive regulatory processes including permitting, siting, and often complex cross-jurisdictional agreements.
  - **Cost-Allocation Mechanisms:** Since transmission projects serve multiple stakeholders, transparent and fair cost-allocation structures are essential to advance these projects efficiently.
- **Demand-Side Management and Resilience Initiatives:** In some cases, the need for additional transfer capability can be mitigated by strategic demand-side solutions. Examples include the following:
  - **Demand Shifting:** Encouraging shifts in demand to non-peak periods through rate structures or operational adjustments.
  - **Energy Efficiency:** Achieving a reduction in demand through the implementation of new technologies.
  - **Targeted Demand Response:** Programs designed specifically for extreme conditions, where demand reduction can alleviate stress on the grid.
  - **Enhanced Storage Deployment:** Energy storage provides backup capacity to release energy to the grid during peak demand, reducing reliance on external transmission sources.

Planners should consider all options and balance reliance on external resources versus internal resources, noting that there may be better options than overreliance on one or the other. Suggestions to meet or maintain transfer capability are provided in the ITCS report.[22]

Study Lessons

Several lessons were identified as part of the ITCS and Canadian Analysis. These include the following:

- Increasing need to conduct wide-area energy assessment and scenario development
- Increasing need to fully incorporate weather impacts in assessments
- Changes to system planning evaluations
- Common datasets, case development, and consistent metrics were identified as essential components of future assessment strategy

Additional details regarding the study lessons are provided in the ITCS report.[23]

Some Canadian energy, resource profiles, and outage data were not readily available, so Planning Coordinators provided them upon request. Easier access to quality data for the Canadian systems would be important for future studies.

[22] https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf, chapter 10
[23] Ibid., executive summary page xxi

Chapter 1: Overview of Scope and Terminology

This study, which follows the ITCS,[24] was requested by Canadian government entities and industry leaders and provides valuable insights regarding potential risks to their systems during extreme events.[25] It also discusses the potential of the transmission system to mitigate energy deficits, particularly from a reliability perspective. Canadian regulators and Planning Coordinators may find it helpful to review the results of this study, perform additional analysis if needed, and determine the appropriate next steps to address the potential energy deficits.

The Canadian Analysis is a comprehensive study of transfer capabilities between adjacent TPRs from the United States to Canada and between Canadian provinces, including neighboring Interconnections. To perform the future-looking energy assessment to determine potential deficiencies, the study used 12 years of data to capture a wide variety of operating conditions and account for historical weather events. It also used internally consistent assumptions and modeling approaches for all neighboring interfaces and TPRs across the North American BPS. This broad view is key when evaluating the support that may be available to assist in meeting energy adequacy requirements while considering transfer capability limitations.

Within this strategic context, the key objectives of the Canadian Analysis are as follows:

- Conduct a comprehensive, repeatable study of existing interregional transfer capability between each TPR to assess current transfer capability and the future need for additional transfer capability that could contribute to reliability under various system conditions, including extreme weather.
- Analyze additions to transfer capability that would increase the amount of energy that can be transferred between neighboring TPRs.
- Engage stakeholders and gather inputs, assumptions, and conditions from Regional Entities, industry, and the Canadian Analysis Advisory Group (Advisory Group) to ensure a comprehensive and inclusive study.
- Identify expectations for the next steps and a continuing analysis of transfer capability to reinforce future NERC assessments, including trends.

Study Scope

The transfer capability analysis studied forecasted 2024 Summer and 2024/25 Winter conditions.[26] This analysis produced a set of transfer capability limits between neighboring TPRs. More information is provided in the associated scoping document.[27]

These results were vital inputs to the energy margin analysis, which identified TPRs that are deficient under the study scenarios, including extreme weather events, based on 2023 LTRA data (with a sensitivity study using 2024 LTRA data). TPRs with an energy deficiency were evaluated first to determine if there was sufficient transfer capability to cover the deficiency. Then, additions to transfer capability were studied.

The energy margin analysis and transfer capability additions process were divided into four tasks:

1. Develop a North American dataset of consistent, correlated, time-synchronized load, wind and solar generation output, and weather-dependent outages.

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[24] The ITCS was mandated by the U.S. Congress in June 2023. See H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress

[25] A list of extreme weather events evaluated is in **Chapter 4**.

[26] For the purpose of this analysis, the summer is May 1 through October 31, and the winter period is November 1 through April 30.

[27] ITCS Transfer Study Scope - Canadian Analysis

2. Conduct an energy margin analysis to identify periods of tight supply conditions and potential resource deficiencies to be further evaluated.
3. Develop metrics and methods to identify which TPRs would benefit from increased transfer capability.
4. Quantify additional transfer capability between each pair of TPRs that would mitigate the resource deficiencies, deliberately evaluating whether neighboring TPRs had surplus energy available to transfer.

The following items were intentionally out of scope for this analysis:

- A probabilistic resource adequacy analysis was not conducted. While 12 years of weather conditions were considered, the study did not attempt to sample hundreds or thousands of potential generator outages and load conditions, nor did it assign probabilities to potential loss-of-load events.
- The relative merits of additional transfer capability compared to local resource additions were not considered. The Canadian Analysis focused on transfer capability as a possible mitigation for energy deficiencies. In practice, strengthening the energy adequacy of the BPS should consider a multifaceted approach that can include adding new local resources (generation or storage), improving load flexibility (demand response), and/or increasing transfer capability.
- The energy margin analysis used a simplified transmission model—often referred to as a "pipe and bubble" model—and did not perform a full nodal, security-constrained economic dispatch or power flow analysis. Instead, it leveraged the TTC values from the transfer capability analysis.

The study used a combination of publicly available and NERC proprietary large hourly datasets for each TPR across North America to conduct an energy margin analysis as part of the transfer capability additions process. The results were compiled to create a multi-year, hourly, time-synchronized dataset of load, wind, solar, hydro, and weather-dependent outages of thermal resources that collectively determine energy margins. The associated scope document[28] contains additional details.

Stakeholder Engagement

The Advisory Group of stakeholders, which includes regulators, industry trade groups, and transmitting utilities, was formed to ensure a comprehensive and inclusive study. The Advisory Group's meetings, which were public, are posted on the ITCS webpage along with other project materials and supporting information. The Advisory Group was assembled with functional and geographic diversity to gather industry input and ensure a comprehensive study. Stakeholders included Natural Resources Canada, the Electric Power Research Institute (EPRI), independent system operators, and a variety of utilities.[29] The monthly meetings were open, and meeting schedules and materials were posted publicly. The Advisory Group provided input to the ERO Enterprise regarding study design and execution and provided insights, expertise, and inputs to the study approach, scope, and results. Throughout the process, NERC reviewed stakeholder comments and incorporated input where appropriate.

NERC adopted a broad approach to consult with and inform all stakeholders, including Transmission Planners, Planning Coordinators, Transmission Operators, Transmission Owners, provincial/federal regulators, and industry trade groups throughout the study progression as shown in **Figure 1.1**.

[28] ITCS SAMA Study Scope - Part 2 (nerc.com)

[29] A full roster for the Canadian Analysis Advisory Group is posted here.

Figure 1.1: Stakeholder Engagement

Regional Entities also worked closely with Planning Coordinators and other industry technical groups in their respective areas.

NERC encourages all stakeholders to continue the constructive engagement and collaboration across provincial and international boundaries to address the challenges facing our grid. NERC is committed to doing its part by integrating transmission adequacy throughout North America into future LTRAs and continuing to highlight risks in its reliability assessments.

Transmission Topology

The TPRs used for this study are shown in **Figure 1.2**.

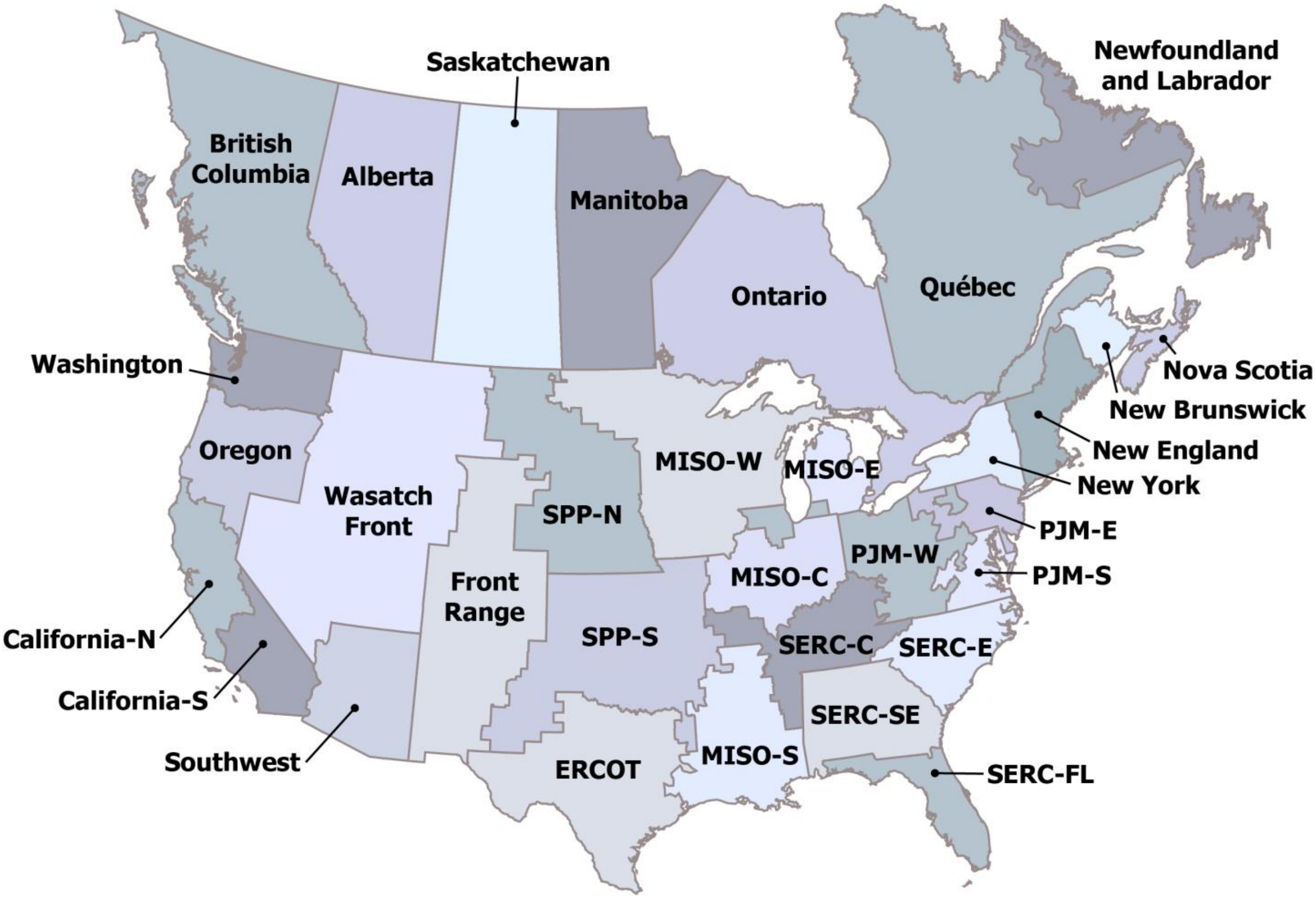

Figure 1.2: Transmission Planning Regions

The transfer capability analysis identified a set of interfaces that included all pairs of neighboring TPRs so that transfer analysis from source (exporting) TPR to sink (importing) TPR and vice versa could be performed. In this context, only electrically connected neighboring systems were evaluated. To more accurately reflect the ability of a TPR to simultaneously import energy from multiple neighbors, the transfer capability analysis also calculated the total import capabilities of each TPR. This evaluation was technically necessary to appropriately model system capability. The power flow models are further detailed in **Chapter 2**.

For the energy margin analysis, a representation of the transmission system was created with transfer capability limits applied to each interface and a total import interface limit for each TPR. These transfer capability limits were calculated in the transfer capability analysis, which analyzed the 2024 Summer and 2024/25 Winter conditions. The model is not intended to represent actual energy flows, nor does it calculate generation shift factors, line impedances, individual line loadings or ratings, or other transmission considerations.

A visual representation of the transmission topology is provided in **Figure 1.3**, which shows each of the existing transmission interfaces represented as a solid line. Dotted lines represent existing dc-only interfaces between TPRs, including connections between Interconnections.

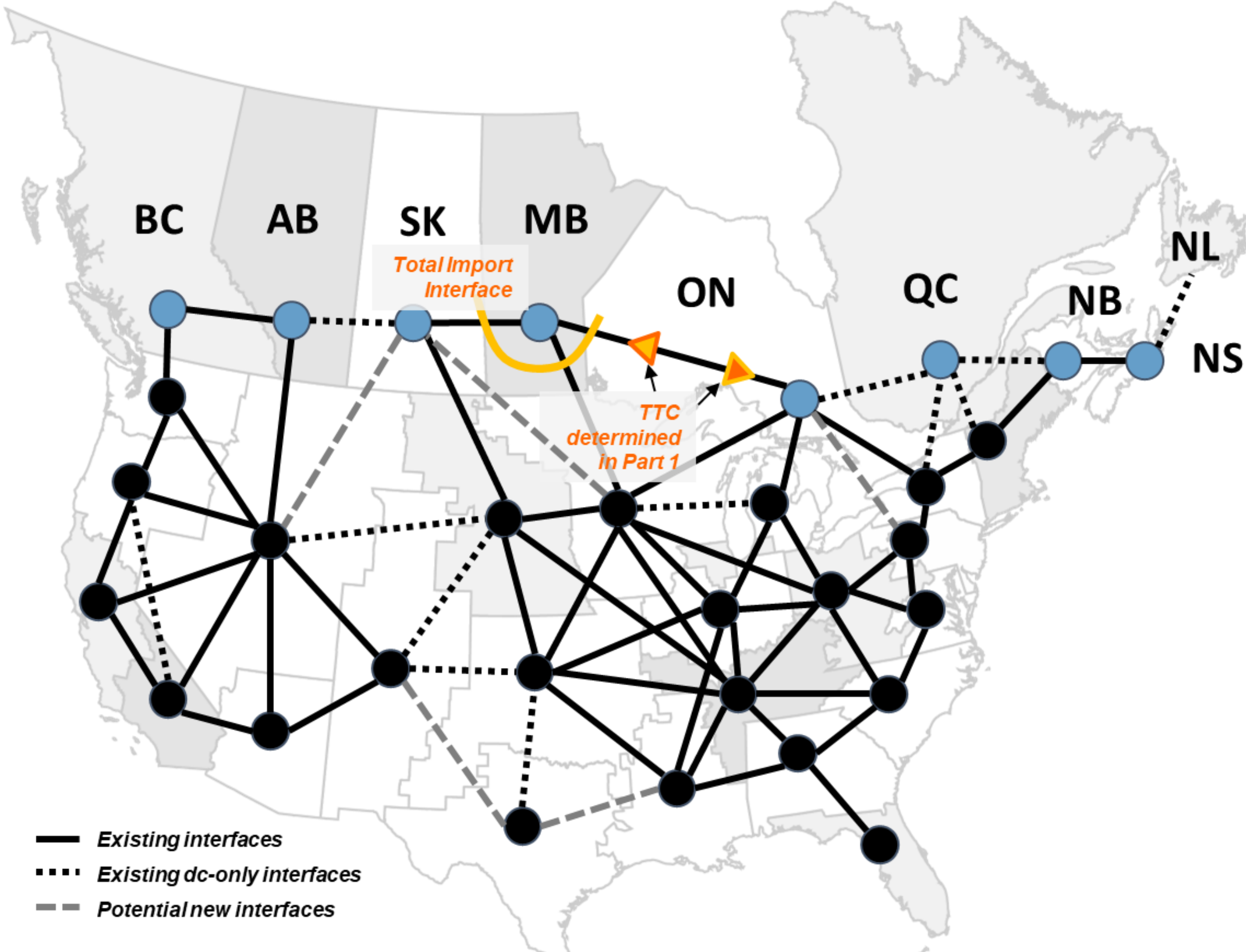

Figure 1.3: Transmission Interfaces Considered

The model also included potential new transmission interfaces between geographically adjacent TPRs even if no transmission linkage currently exists. These candidates are represented as dashed gray lines in **Figure 1.3**. The model used for the energy margin analysis is further detailed in **Chapter 4**.

In this model, each interface has a transfer limit in the forward flow direction (e.g., from Manitoba to Ontario) and a potentially different limit in the reverse flow direction (e.g., from Ontario to Manitoba). A total import interface was also included in the model for each TPR, one of which is represented by the yellow arc in **Figure 1.3**. In addition to the individual interfaces, this total import interface limited the simultaneous imports from all neighboring TPRs. This limit was also calculated in the transfer capability analysis by decreasing generation in each sink (importing TPR) and increasing generation proportionally across all neighboring sources (exporting TPRs). This interface was necessary to reflect limitations to simultaneous transfer capability.

Generation from Newfoundland and Labrador interconnecting to Québec (Churchill Falls) was included as a generator in the Québec system based on data provided in the 2023 LTRA. Generation interconnecting to Nova Scotia (Muskrat Falls) was modeled as a proxy generator via the Maritime Link dc cable using details by Nova Scotia.

Transfer Capability

Each Interconnection consists of a network of transmission lines for redundancy, avoiding reliance on a single path. Electricity transfers flow over parallel paths, introducing a variety of operating constraints. Consequently, planning studies must be performed to ensure that these transfers will not jeopardize the reliability of an Interconnection.

According to the *NERC Transmission Transfer Capability White Paper*:

> "Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, area refers to the configuration of generating stations, switching stations, substations, and connecting transmission lines that may define an individual electric system, power pool, control area, subregion, or region, or a portion thereof."[30]

However, while the transfer capability is a measured amount in MW, there is not a one-to-one correspondence with what new transmission facility (or facilities) could be added. For example, to increase transfer capability between two areas by 200 MW, the two areas may find that a single new line with a rating of 200 MW would not be the sole change to the network. Determining a solution is complex and may involve additions or modifications to multiple transmission facilities while taking into account the other planning considerations.

The white paper further states:

> "In both the planning and operation of electric systems, transfer capability is one of several performance measures used to assess the reliability of the interconnected transmission systems and has been used as such for many years. System planners use transfer capability as a measure or indicator of transmission strength when assessing interconnected transmission system performance. It is often used to compare and evaluate alternative transmission system configurations. System operators use transfer capability to evaluate the real-time ability of the interconnected transmission system to transfer electric power from one portion of the network to another or between control areas. In the operation of interconnected systems, 'transfer' is synonymous with 'interchange."[31]

The Canadian Analysis calculated TTC by determining the amount of additional energy transfers that can be added to base transfers already modeled while respecting contingency limits. Reliable operation requires the grid to be operated to withstand the worst single contingency while remaining within system operating limits, noting that the most severe single contingency may be in a neighboring area. Category P-1 single contingencies were used in this study as defined in NERC Reliability Standard TPL-001-5.1.[32]

TTC is the total amount of power that can be transferred between two areas. TTC is made up of two parts, as shown in Error! Reference source not found.:

- **Base Transfer Level (BTL):** Typically, scheduled power flows between areas in the starting case. These are usually referred to as base flows.
- **First Contingency Incremental Transfer Capability (FCITC):** FCITC simulates an incremental transfer between areas under a single contingency until a system limitation is reached. In other words, it is the amount of energy that can be reliably transferred.

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[30] NERC Transmission Transfer Capability White Paper, 1995, at Transmission Transfer Capability May 1995.pdf (nerc.com), page 5
[31] Ibid., page 7
[32] TPL-001-5 (nerc.com)

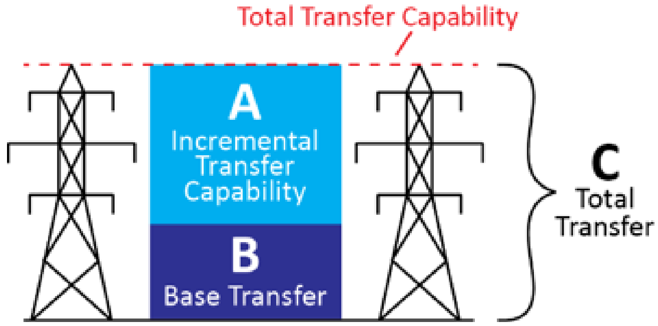


Figure 1.4: Total Transfer Capability

In simple terms, **TTC = BTL + FCITC**. The TTC method enables a consistent calculation across the entire study footprint, while noting that these calculations are different from path limits[33] which are used by some entities.

The BTL for each interface was derived, where available, from the scheduled interchange tables provided with each of the study cases. This was compared to the desired interchange provided in the study cases to cross-check. Where required, adjustments were made to account for additional schedules and market re-dispatch based on load ratio where a Balancing Authority (BA) spanned multiple TPRs. Where the detailed scheduled interchange tables were unavailable, BTL was approximated by using the actual line flow across each interface and cross-checking against the scheduled interchange.

The transfer analysis, which calculates the FCITC, involves simulating incremental transfers from source to sink while applying relevant contingencies and monitoring criteria (described in **Chapter 2**) until a criteria violation is found. The last incremental step before finding a criteria violation is reported as the FCITC. A voltage screening was performed for each transfer analysis to validate the FCITC limit found. Models reflecting this transfer amount were created and screened for voltage violations using applicable contingencies. If a voltage violation was found, the FCITC was reduced and the process repeated until the voltage violation was resolved. All results were vetted by the Regional Entities through the respective Planning Coordinators. If a lower transient stability limit was reported by the Planning Coordinator, then that limit was reported.

Transfer Capability Additions to Strengthen Reliability

Reliability is a broad concept, and significant aspects of required reliability are defined by NERC Reliability Standards and continually implemented through entity planning, investment, and compliance processes. The Canadian Analysis examined transfer capabilities between adjacent TPRs under a variety of weather scenarios and operating conditions that reflect potential extreme conditions, such as those observed during recent events. For this reason, the study is intended to foster discussion on how to improve the delivery of energy under extreme conditions. In fact, when NERC assesses system reliability, it often reviews capacity and energy scenarios to identify system risk. This foundational activity at NERC assesses risks to the BPS in the coming seasons and years.

The Canadian Analysis identified where additions to transfer capability could improve energy adequacy and thereby strengthen reliability by reducing energy deficits. This is not intended to preclude entities from considering other solutions and factors, such as cost allocation or economic advantages.

To identify additions to transfer capability and maintain focus on strengthening reliability, NERC, working with the Regional Entities, developed an approach to apply consistent, objective, and reasonable criteria. This process is described in **Chapter 5**.

[33] The WECC path limits for the Western Interconnection, for example, can be found at https://www.wecc.org/wecc-document/13326.

Important Study Considerations

While the Canadian Analysis used engineering study approaches deployed within industry planning processes, it is not a planning study. Reliability, in the form of energy adequacy, is the sole focus of the study and aligns with the ERO Enterprise's scope and obligations. In contrast, planning studies ensure that electricity is generated, transmitted, and distributed in a cost-effective, reliable, and sustainable manner while meeting applicable environmental and regulatory requirements.

Similarly, this reliability-focused study of transfer capability did not provide economic justification for new and/or upgraded transmission facilities. Rather, the study identified potential increases in transfer capability that could improve energy adequacy during extreme conditions. NERC recognizes that additional transmission has more quantifiable benefits beyond the reliability benefits referenced in this study. For example, these benefits may include factors such as cost savings by providing access to lower-cost sources of generation, voltage support, blackstart, and policy goal implementation. The study is not intended to preclude stakeholders and governmental authorities at the federal, provincial, and local levels from evaluating those additional considerations.

Local solutions, such as additional resources in an energy-deficient TPR, were not considered. This study also does not endorse any particular transmission or generation projects, which may take the form of (but are not limited to) new ac or dc transmission facilities, upgrades to enable higher ratings, grid-enhancing technologies,[34] or a combination thereof.

The Canadian Analysis considered a range of scenarios to ensure robust study results. A sensitivity analysis was also performed to programmatically explore underlying risks. However, the Canadian Analysis is not an exhaustive study of all transmission limitations that may occur during real-time operations or under simultaneous transfers across multiple TPRs.

Due to the unprecedented scope of this study, the transfer capability analysis was limited to steady-state power flow analysis using P-0 (no contingency) and P-1 (single contingency) scenarios as defined in NERC Reliability Standard TPL-001-5.1.[35] In addition to the contingency analysis, a voltage screening was performed for each transfer at the valid limit found using category P-1 contingencies. Notably, while known stability limits were included, the team did not complete short-circuit or stability analysis (i.e., voltage, transient, frequency). Further analysis is recommended to determine solutions after a more comprehensive analysis is performed.

Similarly, a deterministic energy assessment of challenging weather conditions was chosen rather than a probabilistic resource adequacy assessment. This industry-supported approach enables holistic evaluation of the impacts of actual extreme weather events.

This report does not attempt to determine path ratings, load or generator deliverability, available transfer capability (ATC), available flowgate capability (AFC), the availability of transmission service, or to forecast anticipated dispatch patterns. In scenarios where the transfer capability is determined based on internal limitations, the internal flows are not adjusted by re-dispatching resources within the TPR to optimize and enable a higher transfer capability.

Finally, the Canadian Analysis represents a point-in-time analysis using the best available time-synchronized data. Changes to future resource additions, resource retirements, and/or transmission expansion plans could significantly alter the study results. The study team supports conducting energy margin analysis to identify risks in NERC's future LTRA reports on a regular basis to identify trends.

[34] This term references advanced technologies that include dynamic line ratings, power-flow control devices, and analytical tools.
[35] TPL-001-5 (nerc.com)

Chapter 2: Transfer Capability Analysis Process

This section details the study design, tools, case development, and analysis parameters for calculating current transfer capability. The study details were reviewed by various industry groups, including the Advisory Group and Regional Entities' technical groups and committees.

Base-Case Development

The current transfer capability calculation was performed using relevant Eastern Interconnection and Western Interconnection base cases with consistent criteria and assumptions. System models representing the Eastern and Western Interconnections were created to perform the analysis via base cases created through the MOD-032[36] process as a starting point for the following seasons:

- 2024 Summer
- 2024/25 Winter

Base cases were not required for the Québec Interconnection for this study, as it is only tied with the Eastern Interconnection via dc ties.

NERC issued data requests in November 2023[37] to all Planning Coordinators in the Eastern and Western Interconnections to provide base-case updates. Planning Coordinators and Transmission Planners were requested to review these cases and to supply updates, including the following:

- **New generation:** At a minimum, generation with a signed Interconnection Service Agreement was included in the applicable cases.
- **Planned retirements:** Generation that has retired or has announced retirement was removed from the applicable cases.
- **Load forecast adjustments:** Cases were updated to use the most current load forecasts.
- **Resource dispatch:** Changes to reflect the most current resource plans were included.
- **Facility ratings:** Rating changes received, including enhancements since the cases were built, were included in the cases.
- **Expected long-term facility outages:** Facilities expected to be out of service were removed from the applicable cases.
- **Transmission system topology updates:** Changes to topology, including new facility construction, were included in the cases.
- **Base transfers (interchange):** New or updated firm transfers were accounted for in the cases.

Contingencies

The transfer analysis simulated contingencies, namely the unplanned outage of system elements, to ensure that the system would remain reliable during the energy transfer. The following NERC Reliability Standard TPL-001-5.1[38] category P1 contingencies (100 kV and above) were used for the transfer studies:

- P1-1: Loss of individual generators,
- P1-2: Loss of a single transmission line operating at 100 kV or above, and

[36] MOD-032-1 (nerc.com)
[37] This data request was originally issued for the purpose of the ITCS.
[38] TPL-001-5.1 (nerc.com)

- P1-3: Loss of a single transformer with a low-side voltage of 100 kV or above

All contingencies meeting the above criteria within the source and sink TPRs were included in each transfer study, along with all contingencies within five buses from either the source or sink TPR.

Monitored Facilities and Thresholds

Facility monitoring criteria and thresholds were established to prevent undue limitation of transfer capability results based on heavily loaded, electrically distant elements. These practices followed industry-accepted methods to ensure that transmission facilities only minimally participating in an interregional transfer do not artificially constrain the transfer limits. These criteria are further detailed in the scoping document.[39]

Modeling of Transfer Participation

Transfers were simulated by scaling up the available generation in the source TPR in proportion to each unit's remaining availability, namely the difference between maximum generating capacity (P_{MAX}) and its modeled output (P_{GEN}), while scaling down the generation in the sink TPR proportional to its modeled output. Each transfer was simulated until a valid thermal limit was reached while enforcing the source system's maximum generation capacity. If the transfer did not report any transfer limits, meaning that the source TPR was resource-limited, the transfer was repeated without enforcing the source TPR's maximum generation capacity. Invalid limits, such as overloads on generating plant outlets due to not respecting these P_{MAX} values, were ignored.

Special Interface Considerations

Several interfaces have known operating procedures or other special circumstances. In many cases, these are remedial action schemes and/or flow control devices (e.g., phase angle regulators (PAR) or dc lines). There are many situations where these flow control devices have been installed at or near provincial boundaries. The project team worked closely with industry subject matter experts to ensure that these situations were fully understood and properly reflected in the study results.

PAR device settings, including control mode and setpoints, were set in the direction of the transfer being studied and were applied in the case before application of the transfer. These settings were coordinated with the Regional Entities and Planning Coordinators. During the transfer analysis, the PARs were allowed to continue regulation to their setpoints until they reached max angle. This simulates a more representative energy flow during transfer conditions and better represents the overall transfer capability of the interconnected network.

DC lines are typically designed to carry large quantities of energy over long distances and across asynchronous Interconnections. Where an interface consists solely of dc tie lines, the TTC was calculated as the sum of the dc tie line ratings unless limitations on the ac system near the dc terminals were known to be more restrictive.

Finally, there are several situations where one or more units at a power plant can connect to two different Interconnections. These units were modeled as provided in the base cases and the associated capacity was not added to the interface TTC. Similarly, some loads can be switched between the Québec and Eastern Interconnections and were assumed to be part of the Interconnection as modeled in the base case.

[39] ITCS Transfer Study Scope - Canadian Analysis

Chapter 3: Transfer Capability Study Results

This chapter provides the transfer capability results for each interface. An additional section shows the study results for the total import interfaces.

TTC results are highly dependent on the precise operating conditions, including dispatch, topology, load patterns, and facility ratings. This study did not attempt to optimize dispatch or topology to maximize TTC values. Observed transfer capability may be higher or lower depending on the operational conditions.

Figure 3.1 depicts the calculated transfer capabilities for the 2024 Summer case. Figure 3.2 similarly depicts the results from the 2024/25 Winter case.

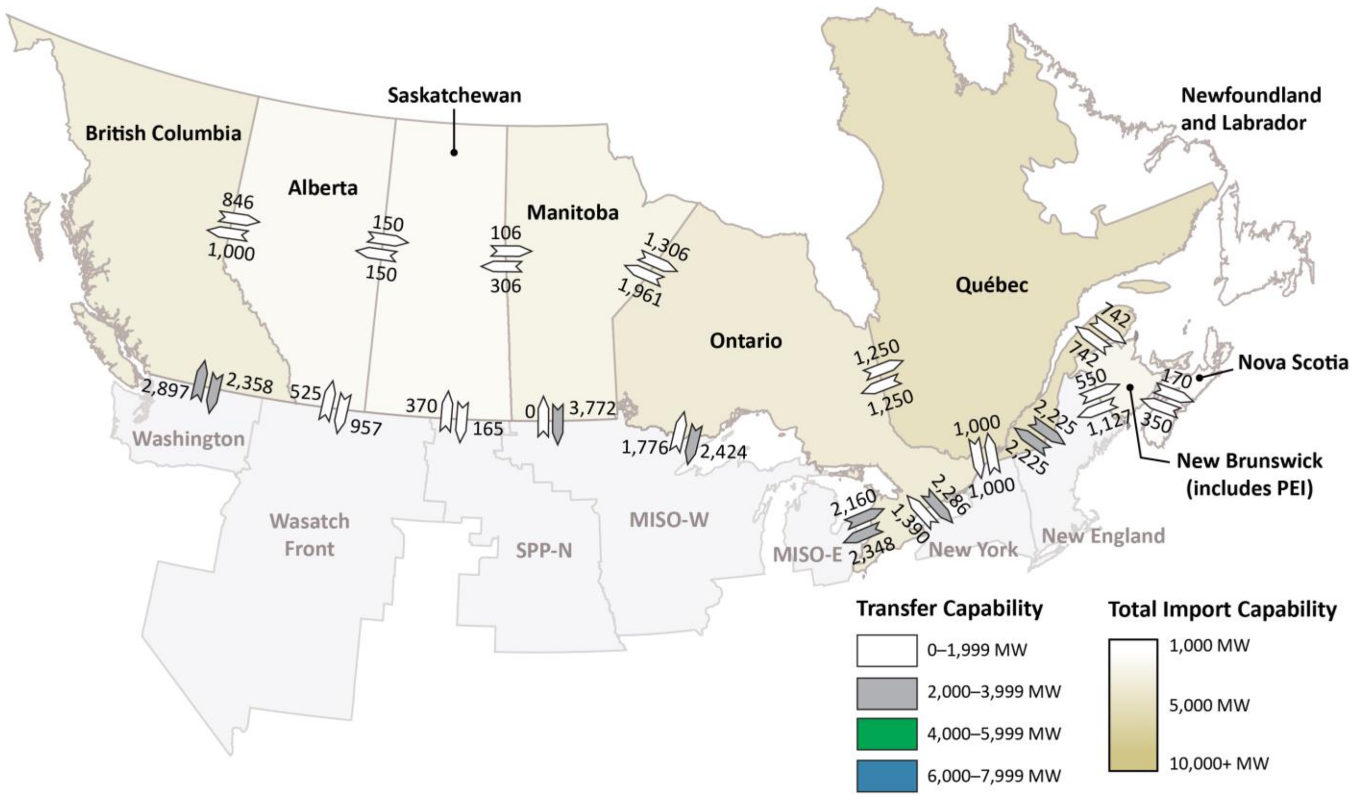


Figure 3.1: Summer Transfer Capabilities

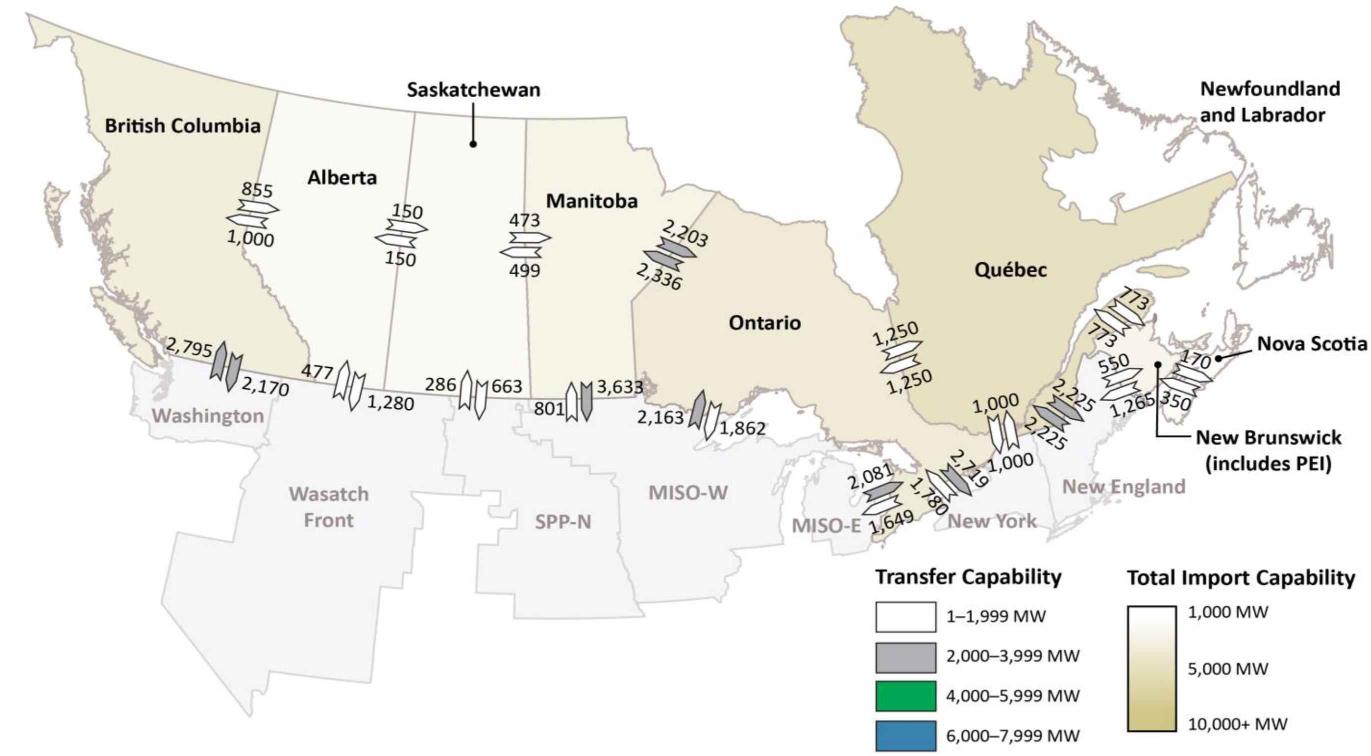


Figure 3.2: Winter Transfer Capabilities

Transfer Capability Results

Results are presented from west to east as follows:

British Columbia <-> Washington

British Columbia <-> Alberta

Alberta <-> Wasatch Front

Alberta <-> Saskatchewan

Saskatchewan <-> SPP North

Saskatchewan <-> Manitoba

Manitoba <-> MISO West

Manitoba <-> Ontario

Ontario <-> MISO West

Ontario <-> MISO East

Ontario <-> New York

Québec <-> Ontario

Québec <-> New York

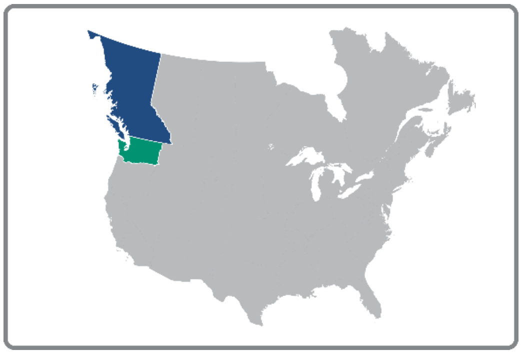
Québec <-> New England

Québec <-> New Brunswick

New Brunswick <-> New England

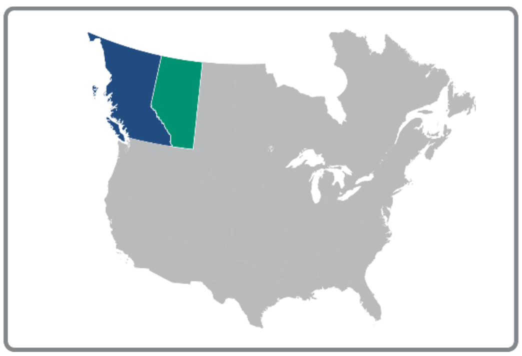
New Brunswick <-> Nova Scotia

British Columbia <-> Washington



Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Washington	2,358 MW	2,170 MW
Washington -> British Columbia	2,897 MW	2,795 MW

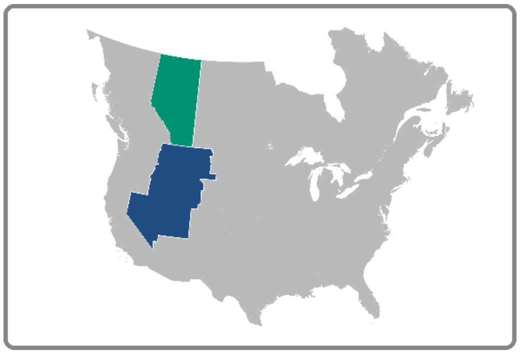
British Columbia <-> Alberta



Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Alberta	846 MW	855 MW
Alberta -> British Columbia	1,000 MW[40]	1,000 MW[41]

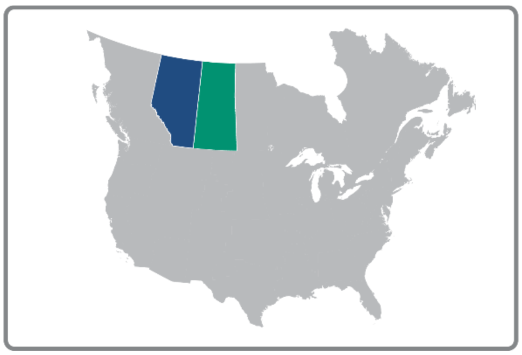
[40] This value is a stability limitation.
[41] This value is a stability limitation.

Alberta <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Wasatch Front	957 MW	1,280 MW
Wasatch Front -> Alberta	525 MW	477 MW

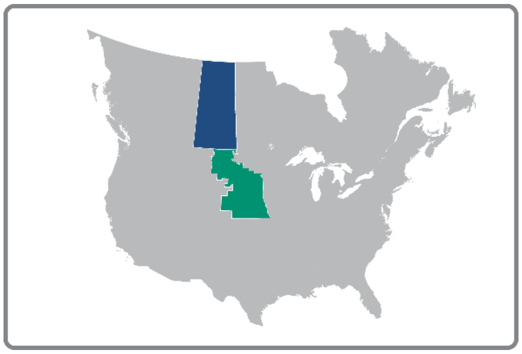
Alberta <-> Saskatchewan



Special Information: dc-only interface

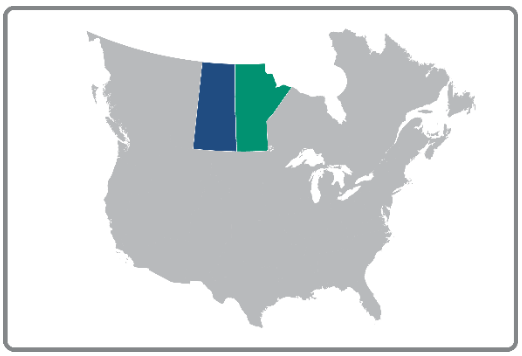
Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Saskatchewan	150 MW	150 MW
Saskatchewan -> Alberta	150 MW	150 MW

Saskatchewan <-> SPP North



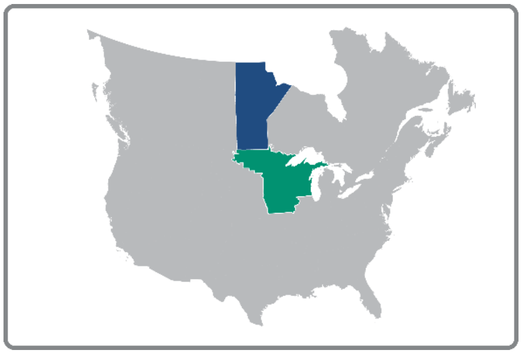
Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> SPP North	165 MW	663 MW
SPP North -> Saskatchewan	370 MW	286 MW

Saskatchewan <-> Manitoba



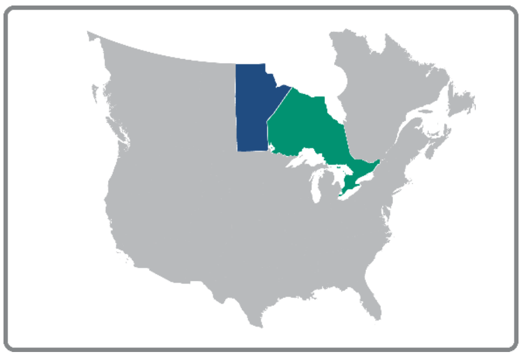
Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> Manitoba	106 MW	473 MW
Manitoba -> Saskatchewan	306 MW	499 MW

Manitoba <-> MISO West



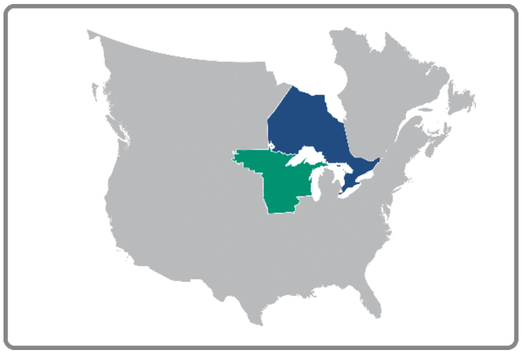
Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> MISO West	3,772 MW	3,633 MW
MISO West -> Manitoba	0 MW	801 MW

Manitoba <-> Ontario



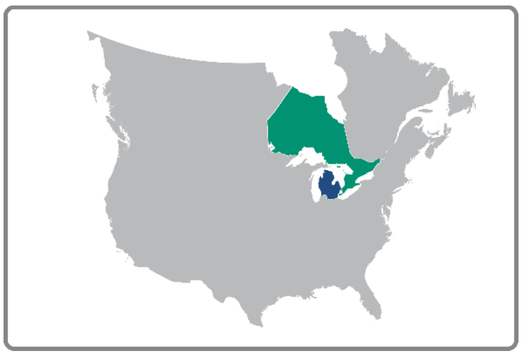
Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> Ontario	1,306 MW	2,203 MW
Ontario -> Manitoba	1,961 MW	2,336 MW

Ontario <-> MISO West



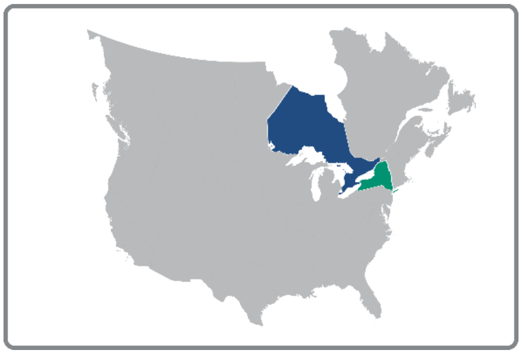
Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO West	2,424 MW	1,862 MW
MISO West -> Ontario	1,776 MW	2,163 MW

Ontario <-> MISO East



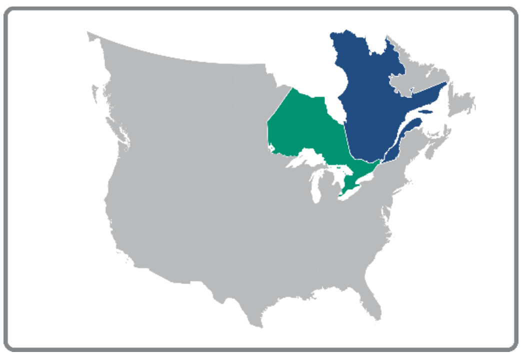
Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO East	2,348 MW	1,649 MW
MISO East -> Ontario	2,160 MW	2,081 MW

Ontario <-> New York



Interface Direction	2024 Summer	2024/25 Winter
Ontario -> New York	2,286 MW	2,719 MW
New York -> Ontario	1,390 MW	1,780 MW

Québec <-> Ontario[42]

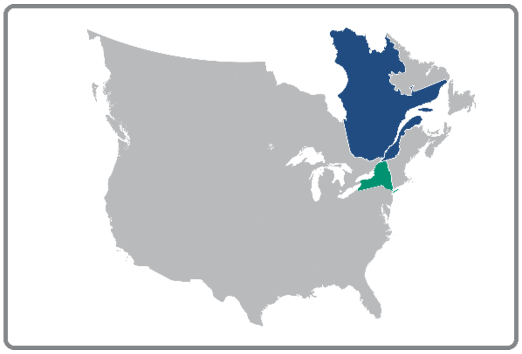


Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> Ontario	1,250 MW	1,250 MW
Ontario -> Québec	1,250 MW	1,250 MW

[42] Transfer capability values listed do not include the ability to switch generating stations between Interconnections, approximately 1,100 MW from Québec to Ontario and 900 MW from Ontario to Québec.

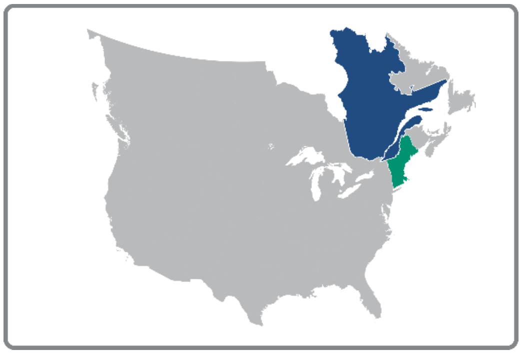
Québec <-> New York[43]



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New York	1,000 MW	1,000 MW
New York -> Québec	1,000 MW	1,000 MW

Québec <-> New England

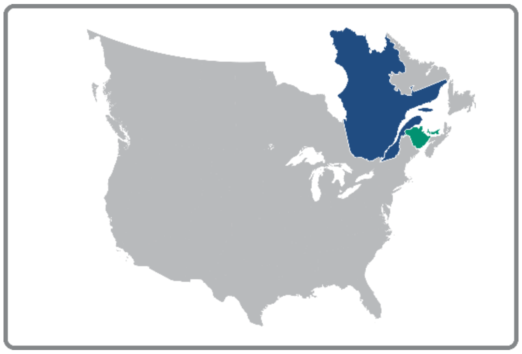


Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New England	2,225 MW	2,225 MW
New England -> Québec	2,225 MW	2,225 MW

[43] Transfer capability values listed do not include the ability to switch a generating station between Interconnections.

Québec <-> New Brunswick[44]



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New Brunswick	742 MW	773 MW
New Brunswick -> Québec	742 MW	773 MW

New Brunswick <-> New England

Interface Direction	2024 Summer	2024/25 Winter
New Brunswick -> New England	1,127 MW	1,265 MW
New England -> New Brunswick	550 MW[45]	550 MW[46]

[44] Transfer capability values listed do not include the ability to switch radial loads between Interconnections.
[45] This value is a stability limitation.
[46] This value is a stability limitation.

New Brunswick <-> Nova Scotia

Interface Direction	2024 Summer	2024/25 Winter
New Brunswick -> Nova Scotia	170 MW[47]	100 MW[48]
Nova Scotia -> New Brunswick	350 MW[49]	350 MW[50]

[47] This value is a stability limitation, adjusted based on exports to Prince Edward Island.
[48] This value is a stability limitation, adjusted based on exports to Prince Edward Island.
[49] This value is a stability limitation.
[50] This value is a stability limitation.

Total Import Interface Results

ERO Enterprise staff analyzed an additional set of transfers into each TPR for the Canadian Analysis. These total import interfaces account for the simultaneous transfer capability into a TPR from all its neighbors. In instances where the calculated total import interface transfer capability was lower than that from any neighboring TPR, the highest neighbor-to-neighbor results were reported to avoid understating the total import capability. The definitions of these interfaces exclude connections via dc-only interfaces, which can typically be scheduled independently. TTC results for the following interfaces are presented in this section:

Into British Columbia

Into Alberta

Into Saskatchewan

Into Manitoba

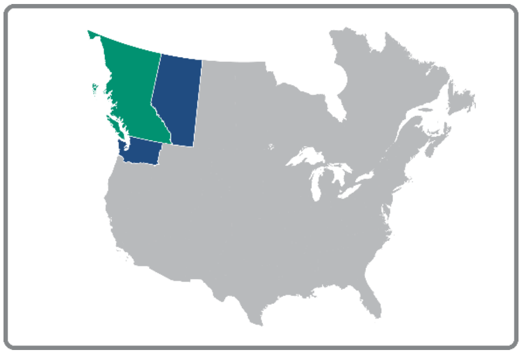
Into Ontario

Into Québec

Into New Brunswick

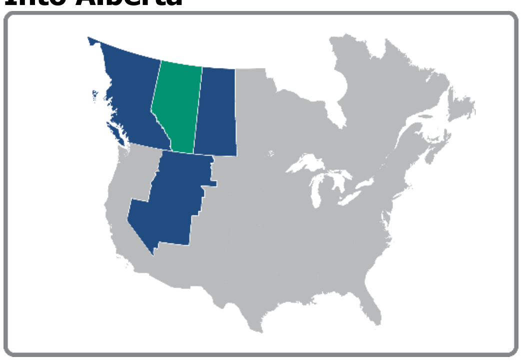
Into Nova Scotia

Into British Columbia



Interface Direction	2024 Summer	2024/25 Winter
Into British Columbia TTC	2,897 MW[51]	3,078 MW
Percentage of Peak Load	31%	27%

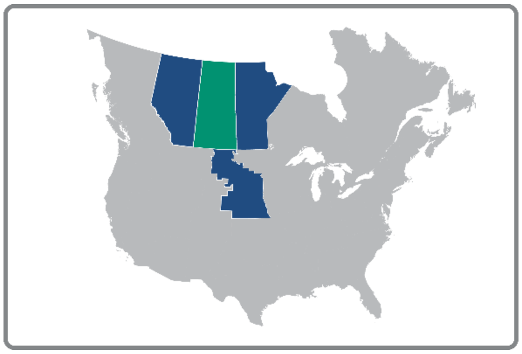
Into Alberta[52]



Interface Direction	2024 Summer	2024/25 Winter
Into Alberta TTC	946 MW	855 MW[53]
dc-only interfaces	150 MW	150 MW
Total of TTC and dc-only interfaces	1,096 MW	1,005 MW
Percentage of Peak Load	10%	9%

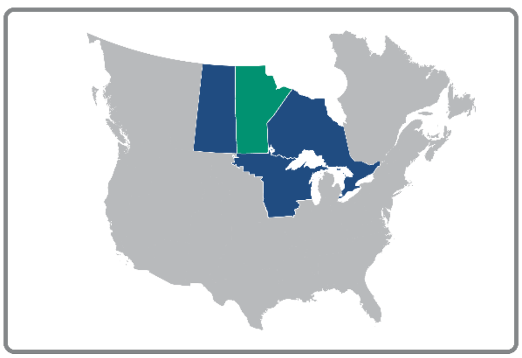
[51] Value is from the Washington to British Columbia interface, as the total import interface calculation was more limiting.
[52] Due to stability limitations, a total export limit of 1,000 MW was applied to Alberta combined exports to British Columbia and Wasatch Front.
[53] Value is from the British Columbia to Alberta interface, as the total import interface calculation was more limiting.

Into Saskatchewan



Interface Direction	2024 Summer	2024/25 Winter
Into Saskatchewan TTC	754 MW	743 MW
dc-only interfaces	150 MW	150 MW
Total of TTC and dc-only interfaces	904 MW	893 MW
Percentage of Peak Load	25%	22%

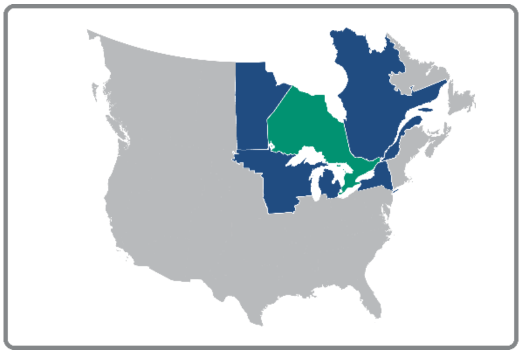
Into Manitoba



Interface Direction	2024 Summer	2024/25 Winter
Into Manitoba TTC	1,961 MW[54]	2,483 MW
Percentage of Peak Load	66%	55%

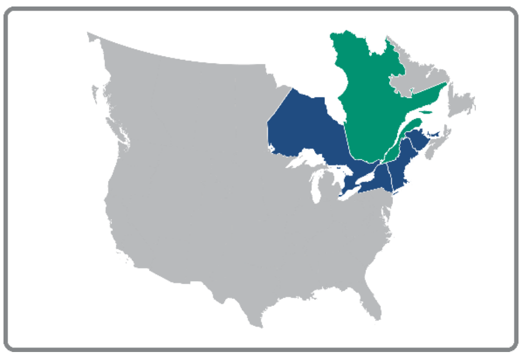
[54] Value is from the Ontario to Manitoba interface, as the total import interface calculation was more limiting.

Into Ontario[55]



Interface Direction	2024 Summer	2024/25 Winter
Into Ontario TTC	2,160 MW[56]	2,203 MW[57]
dc-only interfaces	1,250 MW	1,250 MW
Total of TTC and dc-only interfaces	3,410 MW	3,453 MW
Percentage of Peak Load	14%	15%

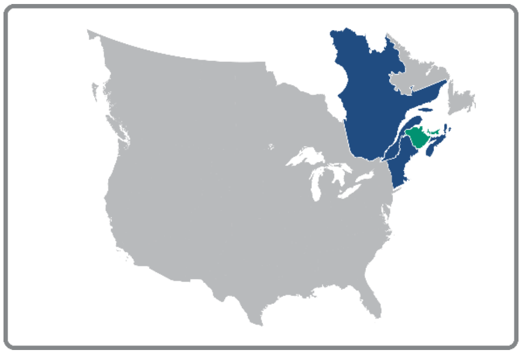
Into Québec[58]



Interface Direction	2024 Summer	2024/25 Winter
Into Ontario TTC[59]	0 MW	0 MW
dc-only interfaces	5,217 MW	5,248 MW
Total of TTC and dc-only interfaces	5,217 MW	5,248 MW
Percentage of Peak Load	21%	13%

[55] Transfer capability values listed do not include the ability to switch generating stations between Interconnections, approximately 1,100 MW from Québec to Ontario.
[56] Value is from the MISO East to Ontario interface, as the total import interface calculation was more limiting.
[57] Value is from the Manitoba to Ontario interface, as the total import interface calculation was more limiting.
[58] Transfer capability values listed do not include the ability to switch generating stations between Interconnections, approximately 900 MW from Ontario to Québec.
[59] Québec operates asynchronously from the Eastern Interconnection.

Into New Brunswick



Interface Direction	2024 Summer	2024/25 Winter
Into New Brunswick TTC	900 MW[60]	900 MW[61]
dc-only interfaces	742 MW	773 MW
Total of TTC and dc-only interfaces	1,642 MW	1,673 MW
Percentage of Peak Load	82%	46%

Into Nova Scotia

Interface Direction	2024 Summer	2024/25 Winter
Into Nova Scotia TTC	170 MW[62]	100 MW[63]
Percentage of Peak Load	13%	5%

[60] This value is a stability limitation.
[61] This value is a stability limitation.
[62] This value is a stability limitation.
[63] This value is a stability limitation.

Chapter 4: Transfer Capability Additions Inputs

Selected Weather Years

A two-pronged approach for inputs and assumptions was used to study a variety of conditions across 12 different weather years. This approach combined synthetic, modeled datasets from 2007 to 2013[64] with historical, actual data from 2019[65] to 2023, as shown in **Figure 4.1**. This combination increased the number of weather years available for analysis and helped overcome the limitations in both datasets.

Figure 4.1: Two-Pronged Approach for Historical Weather Data

Note: The hourly energy margin analysis applied historical weather year data to simulate future grid operations under similar conditions but did not simulate historical operations.

The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historical approach used measured data for load as well as wind and solar resource output from recent years scaled to represent future conditions. These approaches are further detailed in **Appendix A**.

By evaluating all hours of the year across 12 weather years, this study inherently evaluates resource availability, load, and opportunities for energy transfers between TPRs during normal and extreme weather over more than 105,000 hours. The following is a list of known extreme weather events embedded in the analysis:

- Québec Cold Snap, 2009
- Western Wide Area Heat Domes, 2020–2022
- Winter Storm Uri, 2021
- Western and Midwest Heat Waves, 2023
- Northeast Heat Wave, 2023
- Eastern Canada Cold Snap, 2023

While using 12 weather years provides a diverse set of extreme weather conditions to evaluate, this should not be interpreted as representative of all possible conditions. If, for example, one TPR does not show a resource deficiency in the 12 weather years evaluated, this does not mean that the TPR is robust against all weather conditions. This is important when considering when and where resource deficiencies arise and when additional transfer capability can mitigate these risks.

The studied weather years should not be interpreted as representative of all possible extreme weather conditions.

Load Assumptions

A range of load conditions across the grid was studied, time-synchronized and correlated with weather. Of particular interest is the load, which may be much higher during extreme weather conditions than forecasted in the 2023 LTRA data submissions.[66] A combination of historical load (2019–2023) and synthetic load (2007–2013) was used to capture

[64] 2013 is the last year with available NREL Wind Toolkit data.
[65] 2019 is the first full calendar year with available Energy Information Administration (EIA) Form EIA-930 data.
[66] The 2023 LTRA can be found here.

a range of hourly variability in load for each TPR. Recent historical loads were used to capture weather events and associated load behavior as they occurred by using the historical data provided by Canadian utilities. Synthetic loads were used to supplement the range of load behavior during weather conditions that may not be represented in the recent five-year history, with the further benefit of isolating electrification impacts and economic growth in the load profiles. The hourly profiles were then scaled to the LTRA forecasted load on both an energy and seasonal peak basis. Additional details on the data source and load scaling performed for the load profiles are available in **Appendix B**.

The overall goal of scaling the weather-year profiles was to reflect the magnitude and timing of load across each TPR at an hourly granularity, scaled to annual forecasted energy and peak demand targets. The result of the scaling effort maintains the underlying weather variability but increases the overall peak and energy values to align with the LTRA, maintaining variations in seasonal peak load across weather years. This approach was reviewed by the Advisory Group. Tables that show the resulting peak loads are available in **Appendix B**.

Resource Mix

Resource portfolios were aligned with the 2023 LTRA and included existing generators, retirements, and Tier 1 resources.

The LTRA is a NERC assessment of supply and demand on a peak-hour basis that evaluates the winter and summer seasonal reserve margins for North American areas with consideration for the expected contribution of each resource type during the peak load hours. However, the LTRA resource mix was evaluated in the Canadian Analysis across all hours of the year and multiple weather years by varying hourly loads and resource supply.

Two study years were the starting points for evaluation:

- **2024 Case:** Included all existing resources, plus certain retirements and Tier 1 resource additions on-line by the summer season, the 2024 peak load, and the annual energy forecast from the LTRA
- **2033 Case:** Included all existing resources, plus certain retirements and Tier 1 resource additions expected by 2033, the 2033 peak load, and the annual energy forecast from the LTRA

Unit-level information was used to distinguish between fuel types and to map generation capacity to each TPR from the larger LTRA assessment areas. The analysis considered resource availability across aggregated fuel types, including natural gas (single fuel and dual-fuel), coal, oil, nuclear, hydro, land-based wind, offshore wind, utility-scale solar, behind-the-meter solar, pumped storage hydro, and battery storage. It did not perform any unit-specific modeling but captured variability in resource availability at the aggregate level based on historical performance and synthetic weather conditions.

Winter and summer seasonal capacity ratings were used to represent installed capacity for each TPR by fuel type, except for solar and wind resources, where nameplate capacity was used. Using the LTRA winter and summer capacity ratings for 2024 and 2033 ensures that capacity mixes include retirements and units unavailable for other reasons in a manner consistent with the LTRA.

Resources were assigned to TPRs based on their geographic locations. Contractual obligations between generation units and load in a different TPR were not considered. This is an appropriate modeling choice for determining the amount of transfer capability needed to transfer energy from one TPR to another. As such, energy deficiency, as modeled, does not imply that an entity is failing to meet its resource adequacy obligations.

The LTRA generator and load data were aligned to the TPRs used in the transfer capability analysis for both existing and future resource additions. The LTRA Maritimes area was split into New Brunswick and Nova Scotia TPRs for purposes of this study. In addition, a comprehensive data review was conducted by the Planning Coordinators in

Canada working in conjunction with the Regional Entities. Adjustments[67] were made to generating plant capacity to reflect the following manual adjustments:

- Recent coal retirements and repowering in Alberta,
- A delayed coal retirement and a gas addition in Saskatchewan,
- Modifications to nuclear refurbishment schedules in Ontario,
- Adjustments to summer maintenance schedules for hydro and correction to summer season demand response capability in Québec,
- The inclusion of the Maritime Link and hydro capacity in Nova Scotia, and
- Small adjustments to other capacity, predominantly wind, solar, and battery storage to reflect recent changes across various provinces.

Generation from Newfoundland and Labrador interconnecting to Québec (Churchill Falls) was included as a generator in the Québec system based on data provided in the 2023 LTRA. Generation interconnecting to Nova Scotia (Muskrat Falls) was modeled as a proxy generator via the Maritime Link dc cable using details by Nova Scotia.

2024 Resource Mix

Figure 4.2 shows the capacity of the 2024 resource mix by TPR and type based on the LTRA data forms. The winter capacity is shown for thermal and hydro resources, and the installed capacity is shown for wind, solar, and storage resources. Additional details are provided in Appendix C, and summer resource capacities are provided in the TPR-specific tables in Chapter 8.

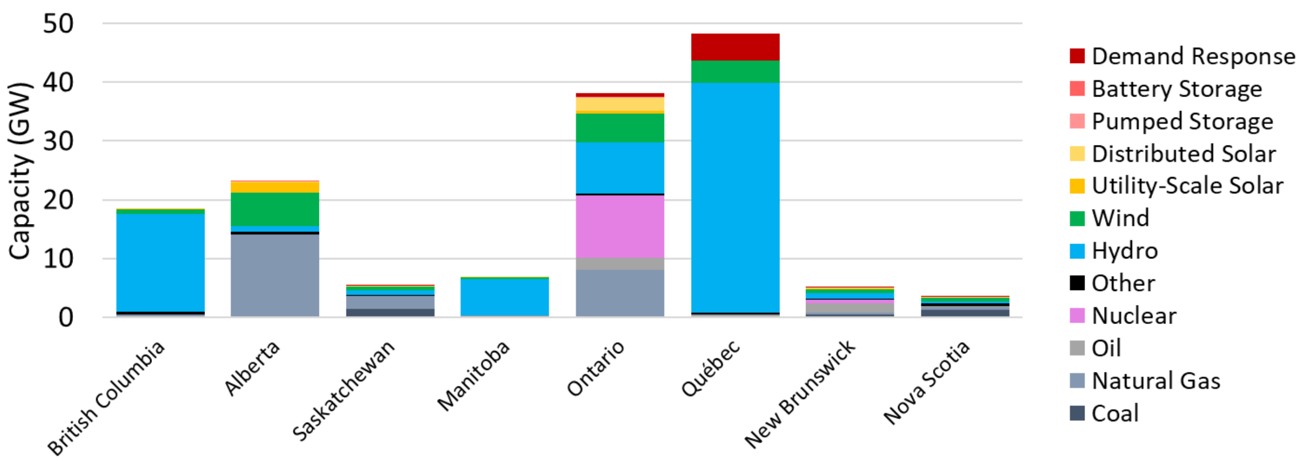


Figure 4.2: Capacity, Existing + Tier 1 Resources (2024 Case)

2033 Resource Mix

The capacity mix for the 2033 study year required adjustments relative to using the existing plus Tier 1 resources provided in the LTRA data forms. Tier 1 resources generally represent plants that are under construction or have high confidence to be on-line. Unlike in the U.S. ITCS analysis, no adjustments were made to incorporate Tier 2 or Tier 3 resources because there were limited plant retirement assumptions that did not already have a Tier 1 replacement already included in the LTRA.

[67] Resource adjustments of this nature were generally not made in the original ITCS due to the number of entities involved, accelerated timing, and the priority of a consistent approach to meet the mandate.

Figure 4.3 shows the 2033 capacity mix by TPR and technology type based on the LTRA data forms.

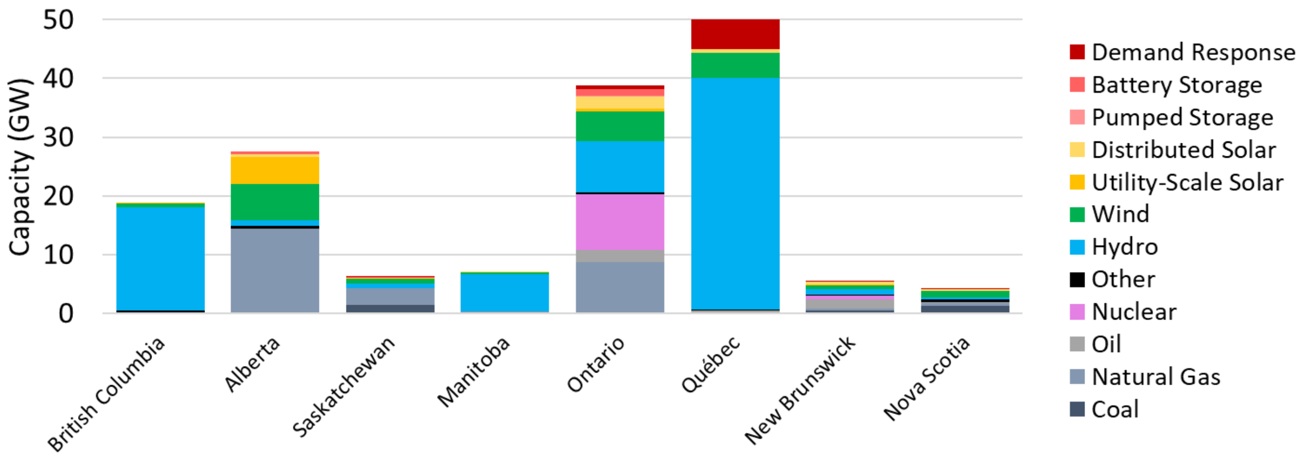


Figure 4.3: Capacity, Existing + Tier 1 Resources (2033 Case)

Resource Modeling

Additional details regarding modeling of certain resource types are documented below. These modeling details were reviewed by the Advisory Group.

Wind and Solar Modeling

Wind and solar resources were modeled using a combination of historical and synthetic weather-year data to represent the hourly energy variability within each TPR. Both datasets described in this section result in hourly capacity factor values for utility-scale solar (UPV), distributed behind-the-meter solar (BTM PV), land-based wind (LBW), and offshore wind (OSW). While the underlying datasets for the historical and synthetic weather years are different, as discussed in Appendix A, both produced a capacity-weighted profile for each resource type within each TPR, normalized to the installed capacity. As a result, this capacity-weighted profile can be used for different levels of renewable resource capacity. In a few cases, historical data was supplemented with synthetic data for the same weather years or historical and synthetic data was used to re-create weather years not covered directly by the historical or synthetic record based on temperature and wind-speed relationships. More details regarding the steps taken to create each set of profiles and descriptions of the underlying data for each weather year profile are provided in the ITCS report.[68]

Hydro Resource Availability

Hydro resources were modeled with monthly maximum availability factors based on historical observations. While they are renewable resources, the availability of hydro is relatively uncorrelated with wind, solar, and load conditions and affected by longer inter-annual cycles in water availability. In addition, hydro resources may be limited in generating at maximum capacity for several reasons, including typical generator maintenance and forced outages. These factors include water levels on rivers and constraints due to reservoir levels. To account for these factors on hydro generating potential, a monthly maximum availability was created for each TPR based on historical data, thereby limiting the maximum generation that hydro resources could contribute. No limitations on monthly or annual energy production were applied, and it was assumed that the maximum output seen in historical records was the limiting factor for hydro resources.

For most provinces, the hydro resources were modeled assuming the observed median maximum hydro generation by month, based on hourly reported data from 2017–2024. In the case of British Columbia and Québec, which are

[68] https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf, appendix B

predominantly hydro-based systems, historical generation is not indicative of the hydro resource capabilities or hydraulic limitations but instead reflects demand profiles and economic export to neighboring markets. In these cases, hydro generation regularly serves most, or all, of the demand throughout much of the year. Discussion with these entities, where needed, resulted in modifications to the monthly hydro capacity used in the simulations to better reflect resource availability. These regions assumed a maximum historical generation that was constant across the year. Monthly maximum rating factors are provided in **Appendix C**.

Thermal Generator Outage Modeling

Thermal generators were aggregated by TPR and fuel type to account for daily fluctuations in available capacity. Thermal capacity was aggregated by up to eight fuel types in each TPR, resulting in 290 unique capacity aggregations across the North American BPS. These aggregations represented the total, fleet-wide resource availability rather than individual generator outage sampling traditionally done in resource adequacy modeling.

Each of the 290 aggregated resource types was then modeled to reflect daily fluctuations in available capacity, accounting for fleet-wide maintenance and forced outages, weather-dependent forced outages, and seasonal maintenance schedules. Ambient derates were reflected for summer and winter based on the associated capacity values provided in the 2023 LTRA data forms.

Capacity on forced outage across Canada was aggregated on a daily basis from 2016 to 2023, derived from voluntary Generating Availability Data System (GADS)[69] data submissions where available (BC, MB, NB, NS) and supplemented with daily utility reported forced outage data where necessary (AB, SK, ON, QC). The analysis shows daily and seasonal variations in forced outages. Unlike what was observed in the U.S. ITCS analysis, Canadian power and natural gas systems are designed to operate in extreme cold and there was no significant correlation observed between outage rates and cold temperatures. However, some regions (SK, NB, NS) have large generating plants relative to the system size, and multiple forced outages occurring simultaneously can create reliability risks. Generator outage modeling was intentionally done on an aggregated fleet-wide basis to capture potential correlated outages across large areas.

Similar to the forced outage rate modeling, planned and maintenance outages and derates were modeled based on voluntary GADS data submissions where available, by day, by TPR, and by fuel type, and supplemented with utility-reported maintenance where necessary. This data, in aggregate, was converted to an average capacity on outage per day as a percentage of net maximum capacity.

Storage Modeling

Storage resources, both pumped storage hydro and battery storage, were modeled as two distinct units for each TPR. Information regarding installed capacity for each resource type for existing and future capacity builds was taken from the 2023 LTRA. Since information on the duration of each storage plant was limited or not available, it was assumed that pumped storage hydro would have 12 hours of duration and battery storage would have four hours,[70] based on trends and available battery storage information from the EIA Form 860.

Storage resources were allowed to charge dynamically within the model to create hourly profiles of charging (adding load) and discharging (generation), subject to round-trip efficiency losses of 30% for pumped storage hydro and 13% for battery storage resources. Storage resources were scheduled to arbitrage hourly energy margins, based on the resource scheduling method described in **Chapter 5**. In doing this, storage was charged during periods of high energy margins (surplus resources) and discharged during periods of lower energy margins. Furthermore, the storage resources did not optimize imports/exports between TPRs, although, during grid stress events, storage resources were allowed to recharge via imports if available.

[69] GADS is a NERC database that includes outages and derates.

[70] In Saskatchewan, battery storage was modeled with a one-hour duration.

Demand-Response Modeling

Demand-response resources were also included in the model as a supply-side resource that could be dynamically scheduled by the model to mitigate resource deficiency events. Like storage resources, demand response was modeled assuming both capacity (MW) and energy (MWh) limitations but did not assume any round-trip energy losses or payback required. All demand-response resources were modeled with a maximum of three hours per day up to the seasonal capacity to ensure they were deployed sparingly. These hourly "per call" constraints were converted into energy constraints, meaning a demand-response resource could be spread over six hours in a day, if needed, but this would have to be done by deploying only a portion of the total capacity.

Demand response was modeled only after energy transfers between TPRs. Demand-response resources were considered the resource of "last resort" to avoid load shedding, deploying only after all local resources and imports were fully exhausted. Energy-limited resources, including battery storage and demand response, were modeled to be used as soon as resource deficiencies occurred on the system and were intentionally not modeled to minimize the maximum resource deficiency. The Advisory Group felt this approach most accurately reflected an operator's decision to utilize battery storage and demand response as soon as necessary to avoid loss of load. Alternative modeling techniques could yield different maximum resource deficiency (MW) values or hours of resource deficiency but would not change the total amount of resource deficiency (MWh).

Demand-response capacity was based on the LTRA Form A data submissions, "Controllable and Dispatchable Demand Response – Available," which represents the estimated demand response available during seasonal peak demand periods.[71] While both "Total" and "Available" demand-response capacity values were reported, the "Available" resource potential was used to represent any assumed derates due to non-performance when called on. A manual adjustment was also made to correct the summer demand response reported for Québec to align with current demand-response capabilities.

[71] For the Maritimes LTRA assessment area, demand response was allocated to New Brunswick and Nova Scotia TPRs proportionally to load.

Chapter 5: Transfer Capability Additions Process

Using the multi-year, hourly, correlated, time-synchronized dataset for load, wind, solar, and thermal resource availability described in **Chapter 1**, the transfer capability additions process identified instances of resource deficiency and evaluated where additional transfer capability would improve energy adequacy. This data-driven process evaluated specific time periods where extreme weather may impact loads and resource availability in one TPR, but neighboring TPRs may have surplus energy available, thus capturing geographic and time zone diversity. This approach considered where resource deficiencies occurred, which interfaces were at their limits, and which adjacent TPRs had available energy to export. Specifically, a six-step process was used to identify and quantify additions to transfer capability, each of which is discussed further in this section:

1. Identify hours of resource deficiency
2. Quantify the maximum resource deficiency
3. Prioritize constrained interfaces
4. Allocate additional transfer capability
5. Iterate until resource deficiencies are mitigated
6. Finalize transfer capability additions

Step 1: Identify Hours of Resource Deficiency

The transfer capability additions process begins with calculating the hourly energy margin for each TPR. Unlike traditional planning reserve margins that evaluate the supply and demand during expected peak load conditions, the energy margin analysis is an 8,760-hour chronological assessment of each TPR's load and availability of resources. The energy margin analysis, therefore, assesses a TPR's potential surplus or deficit across each hour of the year. In addition, the energy margin analysis was conducted over 12 weather years, allowing for fluctuations in load, wind, solar, and thermal resources based on weather conditions, along with seasonal hydro availability.[72]

The energy margin analysis captures the impacts of variable renewables, scheduling of storage resources, expected outage conditions, and load levels associated with specific weather conditions. The formula in **Figure 5.1** below further characterizes the hourly energy margin, followed by an explanation of each property. All properties vary hourly except for available thermal capacity (daily variation) and hydro capacity (monthly variation).

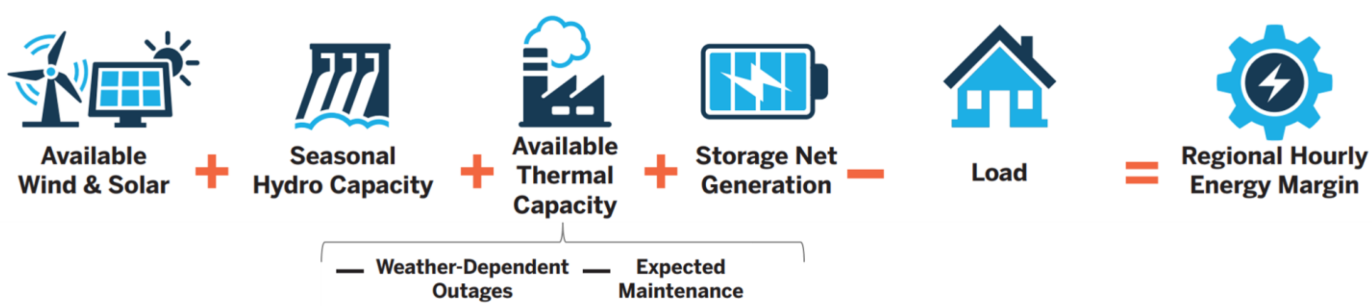


Figure 5.1: Hourly Energy Margin Calculation
Source: Energy Systems Integration Group, 2024

[72] https://www.esig.energy/wp-content/uploads/2024/06/ESIG-Interregional-Transmission-Resilience-methodology-report-2024.pdf

The results of the energy margin analysis provide an *hourly, time-synchronized, locational, and consistent dataset*, allowing for direct comparisons between TPRs. When one TPR has a low hourly energy margin (i.e., a low supply of resources relative to demand), the analysis considers the availability of resources and load in all neighboring TPRs simultaneously. Additional details regarding the energy margin analysis are provided in the ITCS report.[73] Below, **Figure 5.2** shows an example of the time-synchronized load, renewable output, weather-dependent outages, and hourly energy margin.

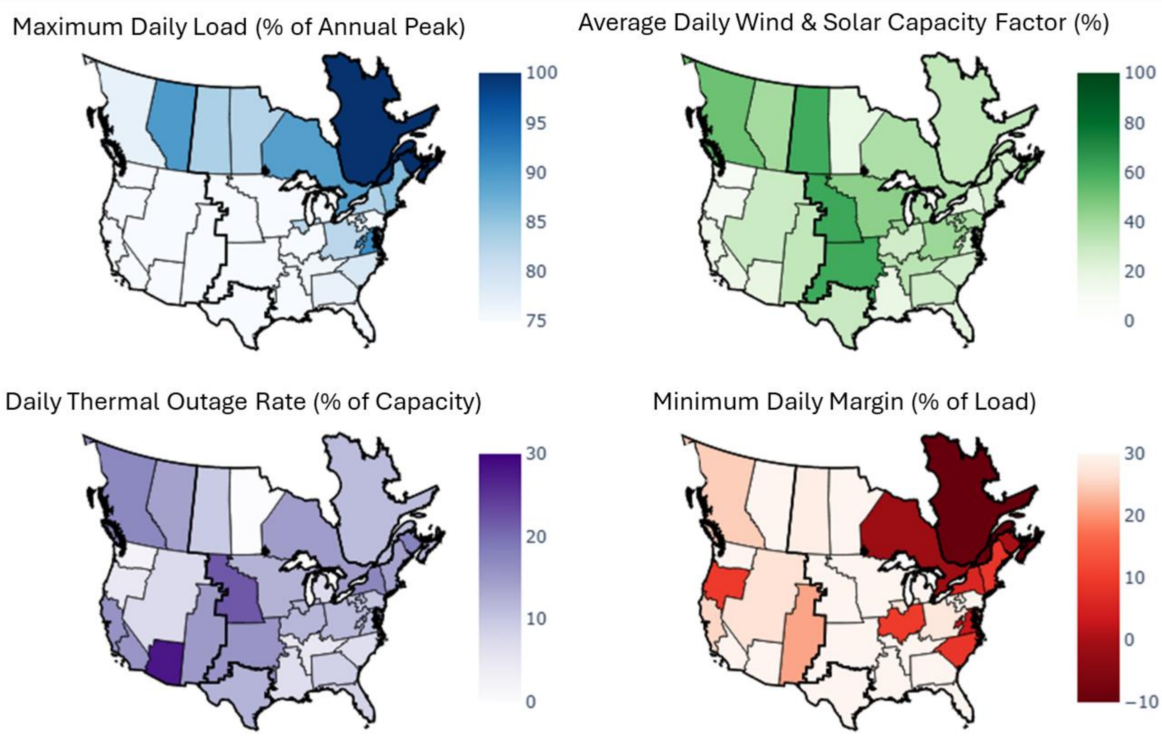


Figure 5.2: Example of Correlated Load, Renewable Output, Weather-Dependent Outages, and Hourly Energy Margin

Resource Scheduling Method

The hourly energy margin is then used to model the available energy across the entire North American BPS for all 12 weather years. This is done to consider the energy adequacy in each TPR, with and without transfers from neighboring TPRs. To isolate reliability needs, resources are first scheduled within a TPR to serve its load before relying on neighboring TPRs. This method allowed for appropriate charge and discharge patterns for energy-limited resources like storage and demand response. The primary reason for using this dispatch model was to ensure that any additions to transfer capability improve energy adequacy (and thereby strengthen reliability) rather than for policy or economic objectives, such as minimizing overall production cost. Operating costs are intentionally not considered for resources in this model. Instead, an operating constraint will increase the scarcity weighting factor in a TPR as the margin between supply and demand becomes tighter. This ensures that the dispatch decisions are driven by relative surplus or scarcity rather than resource dispatch costs. Additional information regarding the dispatch model and scarcity weighting factor calculations are provided in the ITCS report.[74]

[73] https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf, appendix H
[74] https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf, appendix I

Margin Levels

Margins were applied to each TPR's hourly load to account for study uncertainty and operational practices. Unlike a Planning Reserve Margin, which is often denoted in terms of peak demand, these margins are applied to all hours of the year in an equal percentage of demand.

The first threshold, the **tight margin level**, determines when a TPR will seek to import energy. This threshold, applied across all hours, was set at 10% of the TPR's load based on observed projected daily reserves. This level was discussed and endorsed by the Advisory Group.

The second margin, the **minimum margin level**, determines when a TPR will incur unserved energy (load reduction) if additional resources or imports are unavailable. Following multiple discussions with, and feedback from, the Advisory Group, this value was set at 3% of the TPR's load. An additional sensitivity study was conducted using a 6% minimum margin level.

Energy Transfers

Figure 5.3 illustrates the relationship between the hourly energy margin and the conditions under which a TPR may import or export energy. This is crucial for understanding how energy transfers are modeled.

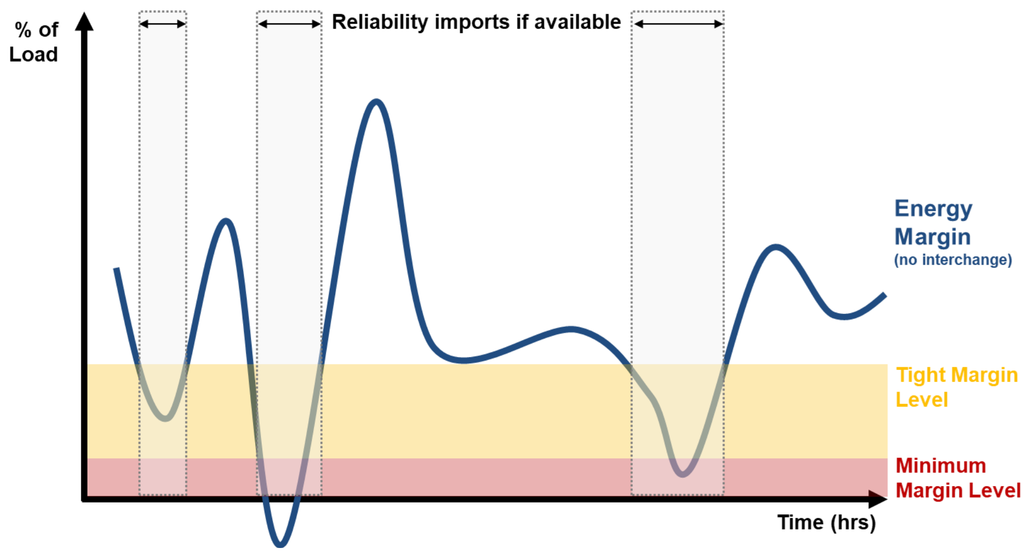


Figure 5.3: Illustrative Example of the Hourly Energy Margin and Reserve Levels

The line represents the hourly energy margin for a TPR, showing the difference between available energy supply and the TPR's load, fluctuating due to changes in supply and demand discussed previously. Two different threshold levels are also shown:

- The **tight margin level** (yellow zone) indicates the desired margin under normal conditions. When the energy margin is above this zone, the TPR is in surplus and is a good candidate to export energy to other TPRs that may need additional energy. When the energy margin is within this level, the TPR has enough capacity to meet its load, but uncertainty in the forecast (e.g., resource mix, load levels, weather impacts, outages) may warrant additional energy imports if available. The tight margin level dictates **when** TPRs will import energy from their neighbors if it is available.
- The **minimum margin level** (red zone) marks the minimum permissible threshold, below which the TPR faces a resource deficiency. In this red zone, it is assumed that the TPR may experience load reduction if energy imports from neighbors are unavailable. This retention of reserves is consistent with normal operating practices, where a BA will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages that would adversely affect overall BPS reliability. The

minimum margin level determines **when** and to **what extent** new transfer capability is considered to mitigate the energy deficiency.

The method for determining transfers between TPRs relies heavily on the tight margin level and minimum margin level. While each TPR initially uses its available resources to meet demand and associated margin, as the energy margin tightens, its scarcity weighting factor increases to reflect the growing need for additional resources.

When a TPR falls below the tight margin level, it begins to import energy from neighboring TPRs. The decision on which neighbor to import from is based on the respective scarcity weighting factors of those neighbors. This ensures that imports are sourced from neighbors with the most surplus capacity (i.e., the lowest scarcity weighting factor). If sufficient imports are unavailable due to transmission interface limits and/or lack of available resources, the TPR may temporarily violate the tight margin level but will still maintain a minimum margin level. This is referred to as a tight margin hour.

If a TPR's energy margin drops to the minimum margin level after exhausting available imports and demand response, the model will decrease the load served, resulting in unserved energy. This is a resource deficiency hour.

Figure 5.4 shows the hourly energy margin after the interchange is scheduled (light blue line). Exports to neighbors are shown as a reduction in the hourly energy margin when a TPR has a relative surplus, while imports are shown as an increase in the hourly energy margin when a TPR drops below the tight margin level.

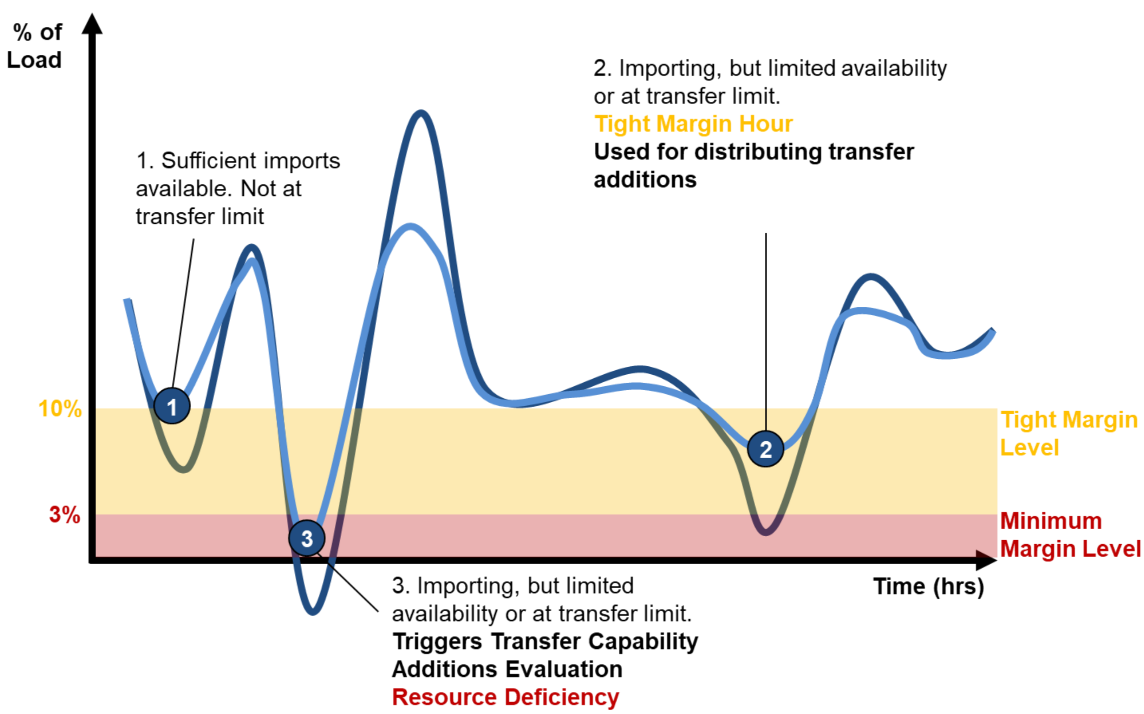


Figure 5.4: Illustrative Example Showing Impacts of Imported Energy

Metrics

Three important points can be considered in Figure 5.4 above:

- **Point 1** indicates that a TPR, in isolation, is below the tight margin level but there is sufficient transfer capability to import energy from its neighbors to maintain the tight margin level. This represents an **interchange hour**. Because the imports allow the TPR to return to its tight margin level, transfer capability is sufficient and not limiting.

- **Point 2** indicates that a TPR is unable to get back to the tight margin level even with imports. At this point, the transfer capability is insufficient and limited and/or neighboring TPRs do not have sufficient resources to share. This point is referred to as a **tight margin hour**.
- **Point 3** indicates that a TPR is unable to get back to the minimum margin level even with imports from its neighbors. In this example, the model will reduce load in the TPR rather than dropping below the minimum margin level, resulting in unserved energy. This is referred to as a **resource deficiency hour** and is used to trigger an evaluation of additional transfer capability as described in later steps.

The model performed the above analysis for all TPRs across all hours over 12 weather years. The calculated metrics, which include the hourly energy margin, are shown in Table 5.1.

Table 5.1: Calculated Metrics		
Metric	**Units**	**Description**
Energy Margin	MW or %	Tracks the hourly energy margin of available capacity relative to load over the course of the year. Quantified in both MW and percent and summarized to show average, minimum, or number of times below a threshold.
Interchange Hour	Hours, MW, or MWh	Quantifies the number of hours, maximum flow, or total energy when a TPR imports to keep its hourly energy margin at the tight margin level. This metric calculates the frequency and quantity of imports for each TPR.
Tight Margin Hour	Hours, MW, or MWh	Quantifies the number of hours in a year, maximum deficit (MW), or total deficit (MWh) when a TPR is below the tight margin level (10%). This metric quantifies how often the transfer capability is insufficient due to interface limit **or** due to lack of resources.
Resource Deficiency Hour	Hours, MW, or MWh	Quantifies the number of hours in a year, maximum deficit (MW), or total deficit (MWh) when a TPR is at the minimum margin level (3%) and experiences unserved energy.
Hours Congested	Hours	Quantifies the number of hours in a year where the transfer capability is at the maximum import capacity. This metric quantifies how often an interface's transfer capability is insufficient.

Step 2: Quantify Maximum Resource Deficiency

In Step 1, the energy margin analysis quantified the frequency, magnitude, and duration of energy deficiency for each TPR. To illustrate the output of this process, a portion of the 2033 energy margin analysis results are shown in Table 5.2 below. Specifically, this table shows the yearly maximum resource deficiency (in MW) for each of the 12 weather years. Winter deficiencies are highlighted in blue and summer deficiencies are shown in orange, while purple highlighting indicates deficiencies in both seasons. The energy margin analysis is further discussed in Chapter 6.

Table 5.2: Maximum Resource Deficiency (MW) by TPR and Weather Year (2033 Case)													
Transmission Planning Region	**WY2007**	**WY2008**	**WY2009**	**WY2010**	**WY2011**	**WY2012**	**WY2013**	**WY2019**	**WY2020**	**WY2021**	**WY2022**	**WY2023**	**Max Resource Deficiency**
British Columbia	0	0	0	0	0	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	519	0	0	0	619	764	0	764
Saskatchewan	543	0	397	0	529	0	116	0	0	0	0	0	543
Manitoba	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario	0	0	155	0	3,083	0	1,591	0	1,358	0	0	147	3,083
Québec	8,113	5,498	4,538	0	0	4,717	6,166	4,329	2,312	0	4,554	10,374	10,374
New Brunswick	0	0	0	0	0	0	0	0	0	0	0	118	118
Nova Scotia	558	547	466	462	496	413	582	305	199	379	260	438	582

The largest yearly maximum resource deficiency identified across all 12 weather years is known as the maximum resource deficiency. This value is a critical input to Step 4, described later.

Step 3: Prioritize Constrained Interfaces

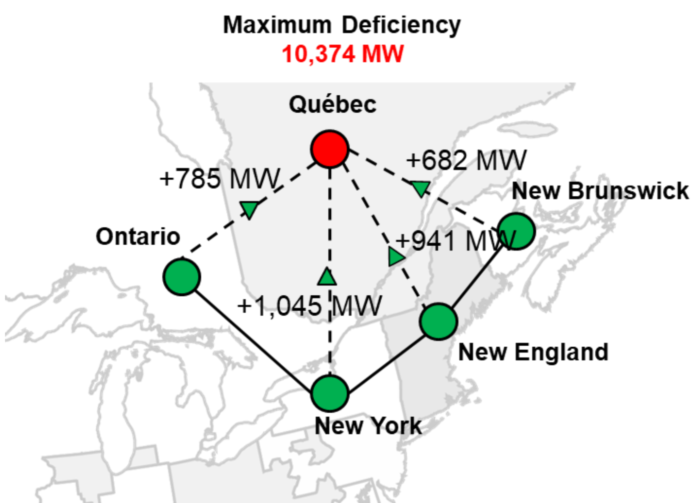
Step 3 focuses on identifying constrained interfaces. After determining which TPRs are in deficit (Step 1) and to what extent (Step 2), the third step is to determine which specific interfaces are constrained during tight margin hours by calculating the number of hours that individual interfaces, including total import interfaces, are transferring energy at their TTC. This is quantified as hours congested across each interface. Additionally, the model calculates the difference between the scarcity weighting factors of each TPR when imports occur and the transmission interface is at its limit. This measures the relative resource surplus between potential sending (exporting) TPRs that could help the receiving (importing) TPR.

The difference between the scarcity weighting factors of the importing and exporting TPRs helps quantify the best candidates for increased transfer capability. In cases where the total import interface is constrained, the difference between the scarcity weighting factor between each pair of TPRs is still quantified and is used as the measure to increase *both* the individual interface capability and the total import interface limit. This calculation is performed for all TPRs.

Step 4: Allocate Additional Transfer Capability

Step 4 focuses on programmatically allocating transfer capability increases to constrained interfaces to address the Maximum Resource Deficiencies (identified in Step 2) using the scarcity weighting factors (calculated in Step 3). Specifically, the model initially allocates transfer capability increases of one-third (33.3%) of the maximum resource deficiency proportionally to interfaces based on the relative difference in scarcity weighting factors, thereby prioritizing neighboring TPRs with relatively more surplus energy available. This partial increase allows the modeling method to capture interactive effects between TPRs and iterative effects as resources are re-dispatched, including exhaustion of surplus resources.

For example, the maximum resource deficiency for Québec is 10,374 MW during a cold snap in weather-year 2023. The initial increase to transfer capability is 3,454 MW, one-third of that amount. Using the difference in the scarcity weighting factors between the exporting TPR and importing TPR from Step 3, this additional transfer capability is allocated 30% to New York (1,045 MW), 27% to New England (941 MW), 23% to Ontario (785 MW), and 20% to New Brunswick (682 MW), as shown in Figure 5.5. Subsequent iterations continue to add transfer capability in increments of one-third of the maximum deficiency, as explained in the next step.



Iteration 1:
Add 3,454 MW to Transfer Capability

Interface	Weight (%)	Addition (MW)
Ontario to Québec	23%	785
New York to Québec	30%	1,045
New England to Québec	27%	941
New Brunswick to Québec	20%	682
Total	**100%**	**3,454**

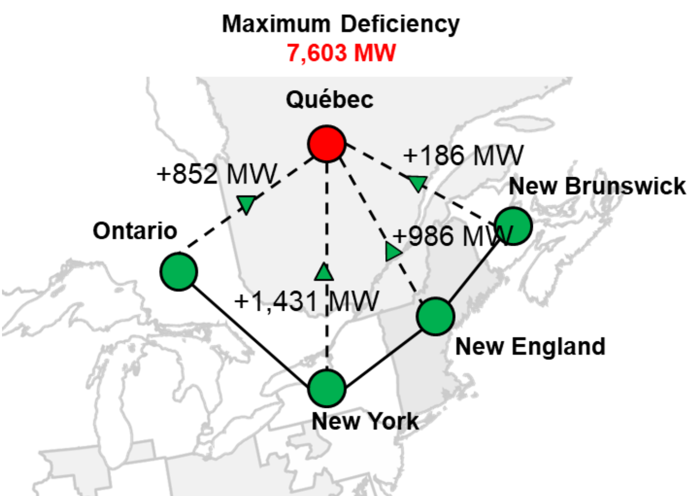
Figure 5.5: Québec Iteration 1 Allocation of Additional Transfer Capability (2033 Case)

Step 5: Iterate Until Resource Deficiencies Are Resolved

Step 5 employs an iterative approach to incremental additions to transfer capability until all resource deficiencies are mitigated (if possible). The modeling method employed in Steps 1–4, including the energy margin analysis, is repeated with the increased transfer capability included.

The study repeated the process of adding transfer capability to constrained interfaces in blocks set at one-third of the original maximum resource deficiency amount until all resource deficiency events were mitigated or until improvements stopped because there were no available resources from neighboring TPRs. This iterative approach ensures that the model accurately reflects the impact of each incremental change on the overall system, captures interactive effects, and allows for the finalization of transfer capability additions to be conducted after all modeling is complete rather than directly in the modeling process.

As shown in **Figure 5.6**, after one iteration of additional transfer capability, the maximum resource deficiency decreased to 7,603 MW, a reduction of 2,771 MW. The second increase to transfer capability is again 3,454 MW (one-third of the original maximum resource deficiency), but this time the allocation is 41% to New York (1,431 MW), 29% to New England (986 MW), 25% to Ontario (852 MW), and 5% to New Brunswick (186 MW), again based on the differences in scarcity weighting factors. This reflects tightening conditions in New Brunswick and is an intentional result of the iterative process.

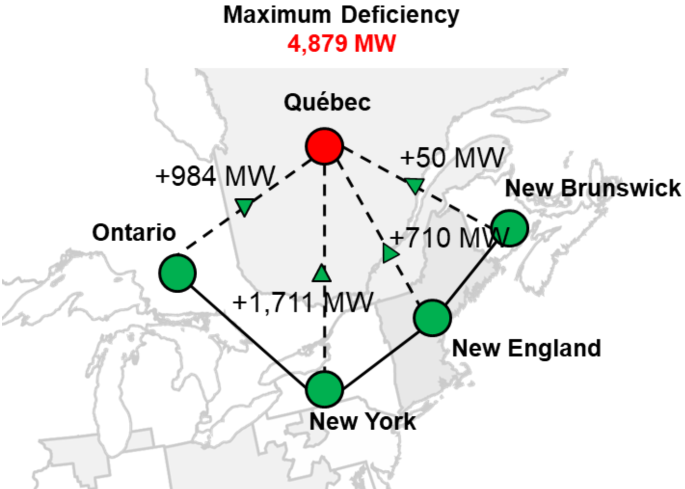


Iteration 2:
Add 3,454 MW to Transfer Capability

Interface	Weight (%)	Addition (MW)
Ontario to Québec	25%	852
New York to Québec	41%	1,431
New England to Québec	29%	986
New Brunswick to Québec	5%	186
Total	**100%**	**3,454**

Figure 5.6: Québec Iteration 2 Allocation of Additional Transfer Capability (2033 Case)

As shown in **Figure 5.7**, after two iterations of additional transfer capability, the maximum resource deficiency decreased to 4,879 MW, a further reduction of 2,723 MW. Since there are still resource deficiency hours observed, the process is repeated a third time. The third increase to transfer capability is again 3,454 MW (one-third of the original maximum resource deficiency), and this time the allocation is 50% to New York (1,711 MW), 28% to Ontario (984 MW), 21% to New England (710 MW), and 1% to New Brunswick (50 MW) as surplus resources tighten in New England and New Brunswick. After the third iteration, all maximum resource deficiency hours have been mitigated, in part due to the multiplier effects described in **Chapter 6**.



Iteration 3:
Add 3,454 MW to Transfer Capability

Interface	Weight (%)	Addition (MW)
Ontario to Québec	28%	984
New York to Québec	50%	1,711
New England to Québec	21%	710
New Brunswick to Québec	1%	50
Total	**100%**	**3,454**

Figure 5.7: Québec Iteration 3 Allocation of Additional Transfer Capability (2033 Case)

Finalize

Step 6: Finalize Transfer Capability Additions

Step 6 uses the results from the multiple iterations of Steps 1–5 described above. After completing all incremental modeling runs, the outputs were used to determine additions to transfer capability. This final step ensures that the transfer capability additions are right-sized and effective, including identification of scenarios where additional transfer capability would not mitigate identified resource deficiencies. As a reminder, these additions were based on the calculated 2024/25 current transfer capability values, applied to the projected 2033 load and resource mix.

Criteria

The following criteria[75] were applied when finalizing transfer capability additions:

- Additions were made to maintain a 3% minimum margin level[76] if possible.
- Where practical, all resource deficiency hours were mitigated (i.e., there was no minimum threshold for the number of resource deficiency hours).
- While all resource deficiency hours were reported for each TPR, additions were only made to address resource deficiencies greater than 300 MW.[77]
- Additions were rounded to the nearest 100 MW increment.
- Additions address limiting interfaces and total import interfaces for the applicable season(s) where resource deficiency was identified.
- Where additions to transfer capability did not significantly reduce the resource deficiency, it was indicative of a lack of surplus energy in the source TPRs such that continued additions to transfer capability would have minimal benefit. Additional transfer capability was considered beneficial for reliability if it did the following:
  - Reduced the maximum resource deficiency by at least 75% of the additional transfer capability, or
  - Reduced the resource deficiency by at least 100% of the additional transfer capability in at least four hours.

[75] These criteria served as mechanisms to guide the application of sound engineering judgment so that transfer capability additions are reasonable. Since Canadian Analysis is a reliability study, economic and policy objectives were not considered.
[76] This level was established based on an evaluation of average reserve requirements where load shed may occur.
[77] This criterion was derived from EOP-004-4.pdf (nerc.com), which prescribes thresholds for disturbance reporting.

Other Considerations

In addition to the criteria above, the following factors should be noted:

- Additions were only considered between neighboring TPRs. Transfer capability additions that solely benefit a "neighbor's neighbor" are outside the scope of this study.
- Additions were prioritized from neighboring TPRs with relatively higher resource surplus, as measured by the difference in scarcity weighting factor discussed in Step 4.
- The bi-directional nature of some transfer capability additions, such as new or upgraded dc lines, was not considered. For example, increased transfer capability from Québec to Ontario to address a deficiency in Ontario could also benefit Québec under different conditions.
- Several generating units can connect to multiple Interconnections (non-simultaneously) without using the associated interface tie lines, meaning they do not deplete the associated transfer capability. This capability should be considered as a potential reduction to the additions and is noted where applicable.

Example of Transfer Capability Additions

Continuing with the Québec example, **Table 5.3** below shows the cumulative iterations of increases to transfer capability. In accordance with the criteria above, these values were rounded to the nearest 100 MW.

Table 5.3: Finalizing Transfer Capability Additions to Québec (2033 Case)

Iteration	Transfer Capability Additions (MW)				Max Resource Deficiency (MW)
	New York	New England	Ontario	New Brunswick	
Base					10,374
Iteration 1	1,045	941	785	682	7,603
Iteration 2	1,431	986	852	186	4,879
Iteration 3	1,711	710	984	50	0
Total	4,187	2,637	2,621	918	
Rounded	**4,200**	**2,600**	**2,600**	**900**	

For other TPRs where the remaining resource deficiency after Iteration 2 was less than the iteration size, Iteration 3 was prorated (before rounding) to right-size the additional transfer capability.

Chapter 6: Additions to Transfer Capability

2024 Energy Margin Analysis Results

The results of the energy margin analysis for the 2024 case are summarized in **Table 6.1**, which provides an overview of the maximum resource deficiencies observed across various TPRs and weather years. This table illustrates how different TPRs perform using the 3% minimum margin level and identifying where resource shortfalls may occur under specific weather conditions. Note that these results include the ability of TPRs to share resources with each other, subject to resource availability and the current transfer capabilities. Blue highlighting indicates that the maximum deficiency occurred in the winter, while orange highlighting represents summer.

Table 6.1: Maximum Resource Deficiency (MW) by TPR and Weather Year (2024 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Max Resource Deficiency
British Columbia	0	0	0	0	0	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0	0	78	174	0	174
Saskatchewan	337	0	175	0	244	0	0	0	0	0	0	0	337
Manitoba	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario	0	0	0	0	0	0	0	0	0	0	0	0	0
Québec	0	0	0	0	0	0	0	0	0	0	0	0	0
New Brunswick	0	0	0	0	0	0	0	0	0	0	0	0	0
Nova Scotia	0	0	0	0	0	0	244	0	0	0	0	0	244

The 2024 case was used for benchmarking, but the simulations did not attempt to re-create actual operations.

The analysis reveals that the 2024 case has relatively few resource deficiencies across most TPRs, indicating that, under the current system, sufficient resources and transfer capability are in place to serve the load under the weather conditions and load levels evaluated. This outcome is significant because it suggests that the existing infrastructure is largely capable of maintaining energy adequacy across diverse scenarios except under the most challenging conditions. The 2024 case is a valuable reference point for future comparisons, particularly when evaluating the 10-year out (2033) case. By establishing a baseline using the 2024 resource mix and load, the study can better assess how future changes in resource mixes, load growth, and extreme weather conditions might be impactful over the next decade. As a reminder, the simulations did not attempt to recreate actual operations or the resource mix from previous years. Instead, they applied the historical weather conditions from those years to the projected 2024 resource mix, providing insights into how the future system might respond to similar extreme events.

In addition to the maximum resource deficiency, the total energy deficiency (GWh) and number of hours of deficiency provide insight into the 2024 case results. **Table 6.2** quantifies the total amount of resource deficiency on an energy basis (GWh). **Table 6.3** provides the number of resource deficiency hours in each weather year. Together, these provide additional information on the size, frequency, and duration of events.

Table 6.2: Total Resource Deficiency (GWh) by TPR and Weather Year (2024 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
British Columbia	0	0	0	0	0	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0	0	<1	<1	0	<1
Saskatchewan	1	0	<1	0	2	0	0	0	0	0	0	0	<1
Manitoba	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario	0	0	0	0	0	0	0	0	0	0	0	0	0
Québec	0	0	0	0	0	0	0	0	0	0	0	0	0
New Brunswick	0	0	0	0	0	0	0	0	0	0	0	0	0
Nova Scotia	0	0	0	0	0	0	1	0	0	0	0	0	<1

Table 6.3: Annual Hours of Deficiency by TPR and Weather Year (2024 Case)													
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
British Columbia	0	0	0	0	0	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0	0	1	5	0	<1
Saskatchewan	8	0	7	0	16	0	0	0	0	0	0	0	3
Manitoba	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario	0	0	0	0	0	0	0	0	0	0	0	0	0
Québec	0	0	0	0	0	0	0	0	0	0	0	0	0
New Brunswick	0	0	0	0	0	0	0	0	0	0	0	0	0
Nova Scotia	0	0	0	0	0	0	13	0	0	0	0	0	1

The 2024 results provide a useful test case for the analysis but were not used to identify additions to transfer capability. Instead, transfer capability additions were based on the 10-year-out analysis, evaluating potential future resource mix and load levels in 2033.

2033 Energy Margin Analysis Results

The 2033 case analysis mirrors the 2024 analysis but accounts for continued load growth, retirements, and new resource additions. The assumptions for load growth, retirements, and resource additions were based on projections from the 2023 LTRA.

Table 6.4 provides a detailed summary of the maximum resource deficiencies observed across different TPRs and weather years for the 2033 case. Like the 2024 results, the table quantifies the maximum resource deficiency observed in each TPR during each weather year, with the last column highlighting the maximum resource deficiency across all weather years. Note that purple highlighting indicates a weather year where resource deficiency hours were observed in both summer and winter.

Table 6.4: Maximum Resource Deficiency (MW) by TPR and Weather Year (2033 Case)													
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Max Resource Deficiency
British Columbia	0	0	0	0	0	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	519	0	0	0	619	764	0	764
Saskatchewan	543	0	397	0	529	0	116	0	0	0	0	0	543
Manitoba	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario	0	0	155	0	3,083	0	1,591	0	1,358	0	0	147	3,083
Québec	8,113	5,498	4,538	0	0	4,717	6,166	4,329	2,312	0	4,554	10,374	10,374
New Brunswick	0	0	0	0	0	0	0	0	0	0	0	118	118
Nova Scotia	558	547	466	462	496	413	582	305	199	379	260	438	582

In contrast to the 2024 case, the 2033 results indicate a more widespread challenge to energy adequacy, with additional TPRs exhibiting resource deficiencies and more weather years posing challenges. This is primarily due to tightening energy margins driven by load growth, the changing resource mix, and the application of current transfer capability to the future case.

In the 2033 case, six out of eight TPRs are affected by resource deficiencies in at least one weather year and, in many cases, across multiple weather years. Three of these TPRs had no deficiencies in the 2024 case.

Similar to the 2024 results, Table 6.5 quantifies the total amount of resource deficiency on an energy basis (GWh) and Table 6.6 provides the number of hours of deficiency in each weather year, thus providing additional information on the size, frequency, and duration of events.

Table 6.5: Total Resource Deficiency (GWh) by TPR and Weather Year (2033 Case)													
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
British Columbia	0	0	0	0	0	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	2	0	0	0	3	7	0	1
Saskatchewan	4	0	2	0	7	0	<1	0	0	0	0	0	1
Manitoba	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario	0	0	<1	0	11	0	5	0	5	0	0	0	2
Québec	154	94	123	0	0	45	138	40	26	0	127	235	82
New Brunswick	0	0	0	0	0	0	0	0	0	0	0	<1	<1
Nova Scotia	14	7	8	6	8	7	16	5	<1	2	3	11	7

Table 6.6: Annual Hours of Deficiency by TPR and Weather Year (2033 Case)													
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
British Columbia	0	0	0	0	0	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	6	0	0	0	10	17	0	3
Saskatchewan	14	0	11	0	26	0	6	0	0	0	0	0	5
Manitoba	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario	0	0	1	0	6	0	5	0	9	0	0	2	2
Québec	45	40	70	0	0	24	57	18	18	0	68	39	32
New Brunswick	0	0	0	0	0	0	0	0	0	0	0	5	<1
Nova Scotia	88	56	47	41	55	61	103	44	12	19	37	78	53

Transfer Capability Additions

As a result of the above analysis, transfer capability additions that could mitigate potential energy deficiencies were identified for five TPRs, summarized in **Table 6.7**, after following the six-step process described in **Chapter 5**. The table is ordered from highest to lowest number of resource deficiency hours as observed in the study. Additional TPR-specific information is provided in **Chapter 8**. Alternative transfer capability additions may also be effective.

Increasing Energy Deficiency Hours

Table 6.7: Transfer Capability Additions Detail					
Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
Nova Scotia	All 12 weather years studied	641	582	500	New Brunswick (500)
Québec	Cold weather in WY2023 and eight other years	379	10,374	10,300	New York* (4,200) Ontario* (2,600) New England* (2,600) New Brunswick* (900)
Saskatchewan	Three heat wave events and cold weather in WY2013	57	543	500	MISO-W** (500)
Alberta	Cold weather in WY2022 and two other years	33	764	600	Saskatchewan* (600)
Ontario	Heat wave in WY2011 and four other years	23	3,083	1,600	PJM-E** (900) MISO-W (400) Manitoba (300)
TOTAL				**13,500**	

** Existing interface is dc-only* *** Potential new interface*

A further discussion of each TPR with transfer capability additions is provided below. Since these additions are based on current transfer capability (2024/25), known planned projects likely to increase transfer capability are noted where applicable. This is not intended as an exhaustive list,[78] nor does it constitute an endorsement of any project; nevertheless, it illustrates that existing industry plans may address some of the identified transfer capability increases. Additional details are provided in **Appendix D** for each of the provinces listed above.

Alberta: Resource deficiencies occurred in a total of 33 hours in winter events spread across three weather years. Following the six-step process described earlier, an addition of 600 MW from Saskatchewan, which provides greater opportunity to share resources between Interconnections, alleviated the identified resource deficiency. Sensitivity studies showed that strengthening the connections with British Columbia or Wasatch Front could also resolve the resource deficiency. Alberta's 2025 Long-Term Transmission Plan[79] describes plans for restoring the British Columbia-Alberta intertie, refurbishing the Alberta-Saskatchewan intertie, and enhancing the Montana-Alberta Transmission Line.

Saskatchewan: Instances of resource deficiency were observed in 57 hours across four weather years. Except in the case of WY2013, these events occurred during summer heat waves. The study identified 500 MW of transfer capability additions needed to resolve the deficiencies, with the optimal choice being a new connection to MISO-West. Other interface options also showed benefit, with SPP-North and Wasatch Front the next highest priorities.

Ontario: Resource deficiencies were found in 23 summer hours in five different weather years, the most severe of which was WY2011. An additional transfer capability of 1,600 MW was found to resolve these deficiencies, including the max deficiency of 3,083 MW, as the additional transfer capability allowed for optimization of storage and other energy-limited resources. The increases for individual transfer capabilities were from PJM-East (900 MW), MISO-West (400 MW), and Manitoba (300 MW). The connection from PJM-East to Ontario would be a new underwater connection across Lake Erie. The ability of generating stations to switch between Québec and Ontario, which was not considered in this study, may also address a portion of the need. Recognizing that the analysis was conducted based on a point in time, it should be noted that Ontario is implementing actions and committing additional projects. Underway and planned procurements under the IESO's Resource Adequacy Framework[80] may mitigate these risks, partially reflected in the 2024 LTRA sensitivity analysis presented in **Chapter 7**.

Québec: Significant resource deficiencies were found in 379 hours during winter extreme cold weather events across nine different weather years. Additional transfer capability totaling 10,300 MW across four different interfaces resolved all the identified instances. The increased transfer capabilities were from New York (4,200 MW), Ontario (2,600 MW), New England (2,600 MW), and New Brunswick (900 MW). The planned 1,250 MW Champlain Hudson Power Express (New York) and 1,200 MW New England Clean Energy Connect (New England) are likely to address a portion of this need.[81] Further, the ability to switch generating capability and/or load serving between Interconnections may also help resolve the identified deficiencies (for example, there is around 900 MW of ac capability from Ontario to Québec). Additional information is provided in Québec's 2035 action plan.[82]

Nova Scotia: Instances of resource deficiency were observed in 641 hours across all 12 weather years, most of which were during winter operating conditions. An additional transfer capability of 500 MW from New Brunswick was identified to address these deficiencies.

[78] Readers are encouraged to review available regional transmission expansion plans for a more complete list of planned projects.
[79] Alberta's 2025 Long-Term Transmission Plan | AESO Engage, see pages iv and 2
[80] Resource Adequacy Framework
[81] Champlain Hudson Power Express and New England Clean Energy Connect commercial operation in the south to north flow direction would require additional authorizations from U.S. authorities.
[82] Action Plan 2035 – Towards a Decarbonized and Prosperous Québec

Other Key Insights

This section provides an in-depth analysis of the critical insights and conclusions drawn from the Canadian Analysis. These observations highlight several key topics essential for understanding the role of transfer capability in mitigating resource deficiencies. These include the following topics, each of which are explored in more detail below:

- Multiplier effects that may enhance the benefits of additional transfer capability
- The intricate relationship between generation and transmission planning
- Pronounced benefits of transfer capability across Interconnections

Multiplier Effects

A key finding of the study is that increasing transfer capability can, at times, reduce the maximum resource deficiency by more than the transfer capability addition. For instance, a 1,000 MW increase in transfer capability can reduce resource deficiencies by more than 1,000 MW, as illustrated by Iteration 3 in the Québec example in Chapter 5. While not immediately intuitive, this can occur for several reasons:

Additional transfer capability can optimize the effectiveness of existing storage resources.

- Storage Resource Optimization: The additional transfer capability allows for pre-charging of storage resources, such as batteries and pumped storage hydro, which might not have been able to charge without the imports. This ensures that these resources, which otherwise would have been depleted, are available during future hours of resource deficiency. This is illustrated in Figure 6.1. An example can be seen in Iteration 1 of Ontario transfer capability additions, which is shown in the associated one-pager in Chapter 8.

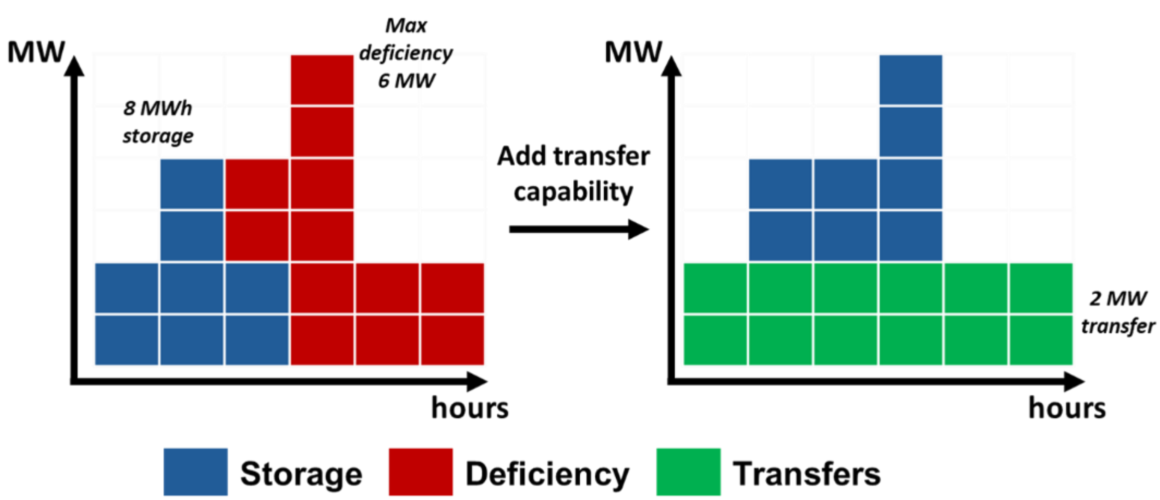


Figure 6.1: Interactive Effects of Transfer Capability and Energy-Limited Resources

- Shortened Deficiency Windows: Increased transfer capability can shorten the duration of resource deficiencies by reducing the window from, for example, six hours to two hours. This enables energy-limited resources like batteries, pumped storage hydro, and demand response to manage the remaining hours more effectively.
- Interactive Effects: Transfer capability additions in one TPR can have cascading benefits for others. For example, an increase in transfer capability can help one TPR mitigate its resource deficiency at one time but may also be used at other times to support a nearby TPR. Additionally, while the study primarily evaluated transfer capability in one direction, new transmission lines or upgrades could increase transfer capability in both directions, providing benefits to both sides of the transfer.

Relationship Between Generation and Transmission

The study found a nuanced but crucial relationship between generation and transmission. If multiple neighboring TPRs lack resources, additional transfer capability offers limited help because there is not enough surplus energy to share. Conversely, if TPRs each have surplus resources, the benefits of additional transfer capability are diminished, as each TPR can meet its own demands locally. Striking the right balance between generation and transmission to meet each TPR's load is essential. However, adding local resources to mitigate deficiencies may also have drawbacks as these new resources could be subject to the same constraints that caused the initial challenge, such as fuel supply restrictions or low renewable availability, leading to correlated risks. The sensitivity studies in **Chapter 7** offer additional information regarding future load and resource mixes.

This finding points to the increased importance of holistic generation and transmission planning. This is particularly important as the resource mix changes and accelerated load growth is expected relative to the past decade. The Canadian Analysis evaluated the role of interregional transfer capability to improve energy adequacy reliability across different resource mixes and study years and did not evaluate tradeoffs between resource and transmission options. This is identified as an area of interest in **Chapter 9**.

Pronounced Mutual Benefits of Transfer Capability Across Interconnections

The study highlighted the mutual and significant benefits of bi-directional transfer capability across Interconnections, where geographic diversity in resource availability and load proved advantageous. For example, the ties between Québec and the Eastern Interconnection demonstrated substantial benefits during extreme weather events. Specifically, these ties helped Québec during severe cold conditions and aided other provinces and states during summer conditions. Similarly, transfer capability between the Western and Eastern Interconnections also provided support, with additional transfer capability between Alberta and Saskatchewan showing reliability benefits. Neighboring Planning Coordinators and Transmission Planners across Interconnections should continue to work toward a wider area planning approach.

Chapter 7: Sensitivity Analysis

In addition to the 2024 and 2033 cases discussed in the previous sections, a series of sensitivity analyses were conducted to evaluate the impact of varying specific assumptions on the overall results. These sensitivities were designed to isolate the effects of individual factors and quantify their influence on resource deficiencies and the need for increased transfer capability. By examining these factors in isolation, this sensitivity analysis provides a clearer understanding of how changes in assumptions might alter the outcomes of the study.

The sensitivity analyses provide valuable insights into how different assumptions can influence study outcomes, including the necessity for enhanced transfer capability. By understanding these dynamics, future planning can be more responsive to a range of potential scenarios.

6% Minimum Margin Level Sensitivity

In this sensitivity analysis, the minimum margin level was increased from 3% to 6%, effectively reducing the surplus energy in all TPRs simultaneously. This adjustment increased the size, frequency, and duration of resource deficiencies, the number of TPRs experiencing these deficiencies, and the magnitude of transfer additions evaluated. **Table 7.1** compares the maximum resource deficiency between the 3% and 6% minimum margin levels. The 6% minimum margin level sensitivity introduces greater levels and frequency of resource deficiency for the six TPRs that showed resource deficiency in the 3% case.

Table 7.1: Comparison of Maximum Resource Deficiency (in MW)

Transmission Planning Region	Max Resource Deficiency (3% Margin)	Max Resource Deficiency (6% Margin)	Change in Max Resource Deficiency
British Columbia	0	0	0
Alberta	764	1,463	699
Saskatchewan	543	662	119
Manitoba	0	0	0
Ontario	3,083	3,901	818
Québec	10,374	11,944	1,570
New Brunswick	118	787	669
Nova Scotia	582	658	76

The iteration method described in **Chapter 5** was performed for the 6% minimum margin level sensitivity. This sensitivity highlights the importance of considering generation and transmission planning holistically. This is because the more restrictive minimum margin level simultaneously reduces surplus resources for all TPRs, exacerbating resource deficiencies and reducing the effectiveness of existing and additional transfer capability. The results of the iterations for the 6% minimum margin level sensitivity in **Figure 7.1** reflect where all deficiencies were resolved for a TPR or where additional transfer capability was no longer beneficial due to saturation effects or lack of resources. Notably, deficiencies in Québec, New Brunswick, and Nova Scotia could not be resolved during an extreme cold snap in WY2023, which resulted in lower transfer capability additions into Québec. In addition to more resources or demand management, new transmission connections to non-neighboring TPRs could also be explored.

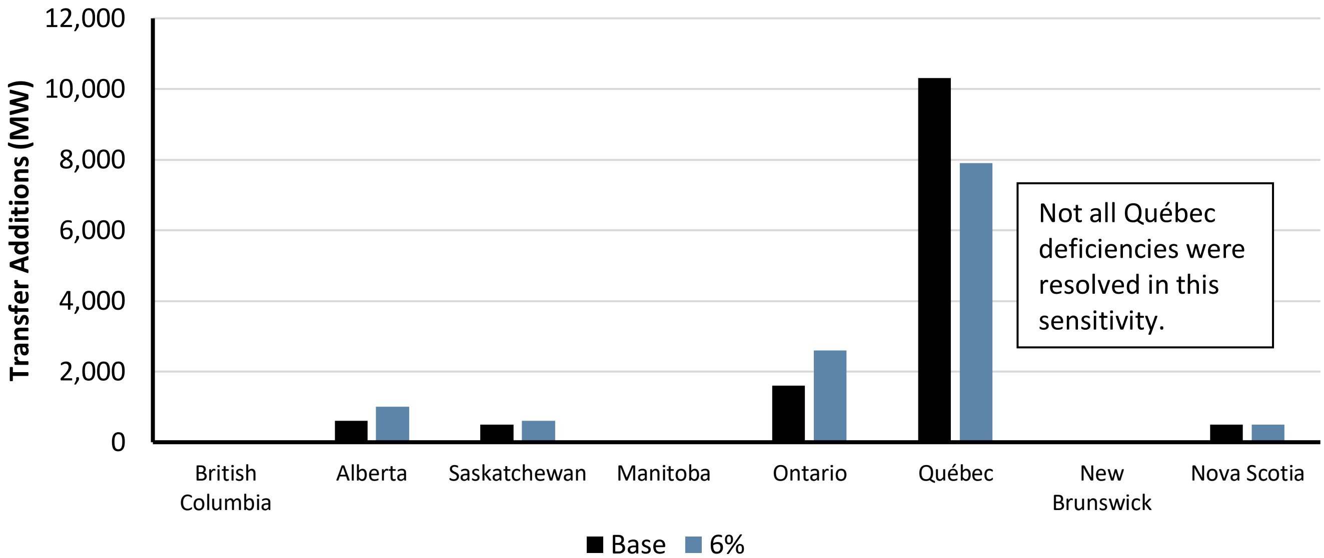


Figure 7.1: Change to Transfer Capability Additions (6% Sensitivity)

Updated Loads and Resources from the 2024 LTRA Sensitivity

In this sensitivity, load and resource forecasts were updated based on 2024 LTRA data. Due to its mandated timing, this was not an option available for the original ITCS. This sensitivity provides more recent projections that can inform the Canadian Analysis results, but outcomes may differ significantly if actual load and/or resources vary from these future projections. Table 7.2 shows the change in the maximum resource deficiency.

These results show a mix of changes in the resulting energy margin analysis results. Specifically, maximum resource deficiencies were reduced in three provinces, most notably in Ontario and Québec, with the small deficiency in New Brunswick entirely resolved. However, the maximum deficiency increased in three other provinces, most notably Alberta, based on the updated resource and demand forecasts.

Table 7.2: Comparison of Maximum Resource Deficiency in 2033 (in MW)

Transmission Planning Region	Max Resource Deficiency (2023 LTRA Data)	Max Resource Deficiency (2024 LTRA Data)	Change in Max Resource Deficiency
British Columbia	0	0	0
Alberta	764	1,395	631
Saskatchewan	543	572	29
Manitoba	0	0	0
Ontario	3,083	643	-2,440
Québec	10,374	9,181	-1,196
New Brunswick	118	0	-118
Nova Scotia	582	584	2

The results of the iterations for the 2024 LTRA data sensitivity in Figure 7.2 reflect where all deficiencies were resolved for a TPR.

As time progresses, the nature and severity of energy adequacy risks will evolve, thereby changing the effectiveness of transfer capability. This evolution strongly indicates that periodic studies that evaluate future resource mixes across many hours of chronological load and resource availability would be beneficial.

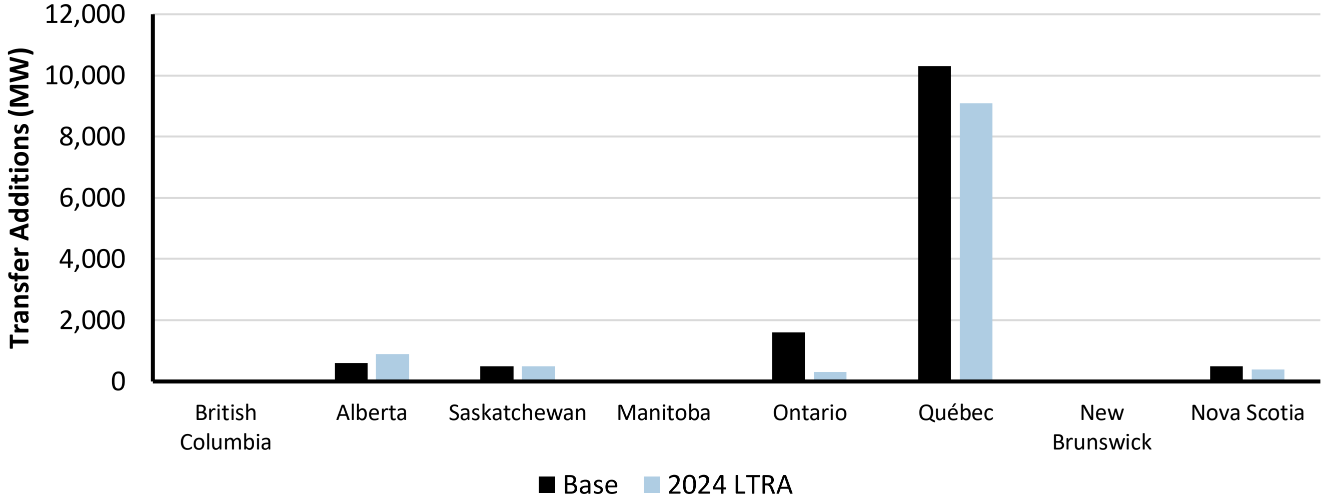


Figure 7.2: Change to Transfer Capability Additions (2024 LTRA Data Sensitivity)

Chapter 8: TPR-Specific Results

The following pages provide detailed results for each TPR, including information on each interface transfer capability, additions to transfer capability, information on each model iteration, assumed resource mix and peak load data, and details on resource deficiency events. Summary maps of transfer capability are also provided, with current transfer capability presented on the top, and additions highlighted in blue on the bottom. The map is provided for the season when transfer capability is required or for the peak demand season if there are no identified deficiencies. All data is provided for 2033 unless otherwise noted. Each of the following pages is organized as follows:

Transfer Capability Summary Section

- Current summer and winter transfer capability columns include each of the interface names importing to the TPR summarized along with the summer and winter transfer capability quantified in the transfer capability analysis.
- The additions column provides the results of the simulations and the additions to transfer capability for each interface.
- Resulting summer and winter transfer capability columns provide the TTC for each interface with additions to the current transfer capability. Additions are only added in the season(s) that they are needed to mitigate resource deficiencies.
- The total import interface limit represents the simultaneous import transfer capability determined, excluding any transfer capability on dc-only interfaces, which is added to the following line if applicable.
- The total import interface + dc-only interfaces limit is provided both in MW and normalized as a percentage of the TPR's 2033 peak demand.

Energy Adequacy by Iteration Section

- This section provides information on each iteration of the simulation, whether or not transfer capability was added for the respective TPR. In general, the energy adequacy metrics will improve in each iteration.
- Tight margin hours and resource deficiency hours quantify the total number of hours with tight margins (<10%) and resource deficiencies, respectively, after accounting for available transfers from neighbors. This is the total number of hours for all 12 weather years.
- Max resource deficiency represents the largest resource deficiency during the 12 weather years.
- Total deficiency is the total GWh of resource deficiency across the 12 weather years.

Capacity and Load Data Section

- Resource capacity is presented for 2024 and 2033 by resource type. Thermal capacity includes coal, nuclear, single-fuel gas, dual-fuel gas, oil, biomass, geothermal, and other fuels. Variable renewable resources include land-based wind, offshore wind, utility-scale solar, and BTM PV. Energy-limited resources include pumped storage hydro, battery storage, and demand response.
- Winter capacities are provided for all thermal and hydro capacities. Nameplate capacity is provided for variable renewable and energy limited resources.
- Summer and winter peak demand is provided for 2024 and 2033 and represents the median peak demand, inclusive of BTM PV resources, but before demand response.

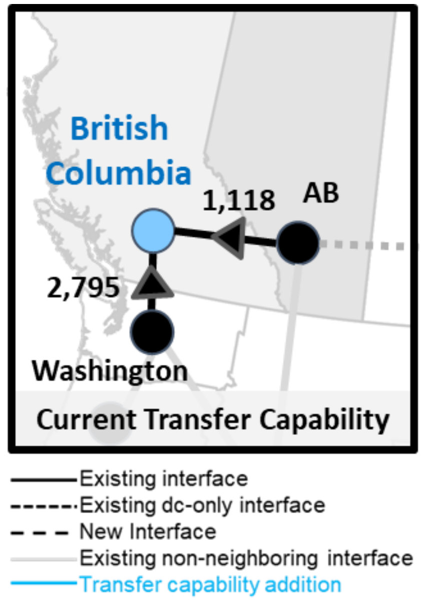
Resource Deficiency Events Section

- The summary statistics for each day of resource deficiency in the base 2033 case are provided if applicable.
- Daily peak demand represents the day's highest load, regardless of when it occurs. Resource deficiency hours may occur before or after the peak demand hour due to variable renewable resources and energy-limited resources having changing availability throughout the day.

Results for the following interfaces are presented in this chapter:

British Columbia

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Additions (MW)	Resulting Summer (MW)	Resulting Winter (MW)
Washington to British Columbia	2,897	2,795	N/A	N/A	N/A
Alberta to British Columbia	1,000	1,000	N/A	N/A	N/A
Total Import Interface Limit	**2,897**	**3,078**			
Total Import Interface Limit + dc-only Interfaces Limit	**2,897**	**3,078**			
(as % of 2033 Seasonal Peak)	**29%**	**24%**			



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	4	0	0	0.0
Iteration 1	N/A	4	0	0	0.0
Iteration 2	N/A	3	0	0	0.0
Iteration 3	N/A	2	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	884	501
Hydro	16,710	17,488
Variable Renewable	764	764
Energy Limited	0	0
Total	18,358	18,753

Note: Thermal and hydro values represent winter ratings

Summer Peak	8,961	9,897
Winter Peak	11,938	12,970

Note: Median peak demand across all weather years

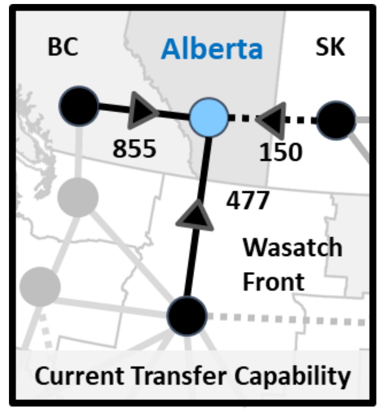
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

Alberta

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Additions (MW)	Resulting Summer (MW)	Resulting Winter (MW)
Saskatchewan to Alberta	150	150	600	N/A	750
Wasatch Front to Alberta	525	477	0	N/A	477
British Columbia to Alberta	846	855	0	N/A	855
Total Import Interface Limit	**946**	**855**	N/A		**855**
Total Import Interface Limit + dc-only Interfaces Limit	**1,096**	**1,005**	**600**		**1,605**
(as % of 2033 Seasonal Peak)	**9%**	**8%**			**12%**

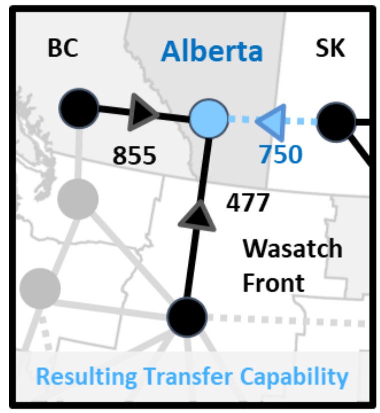
Note: Alternate allocation of additional transfer capability to other neighbors may also resolve the identified deficiencies.



Existing interface
Existing dc-only interface
New Interface
Existing non-neighboring interface
Transfer capability addition

Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	283	33	764	11.8
Iteration 1	254	172	21	510	4.1
Iteration 2	254	103	3	135	0.3
Iteration 3	254	55	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years



Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	14,538	14,916
Hydro	894	894
Variable Renewable	7,642	11,334
Energy Limited	190	463
Total	23,264	27,607

Note: Thermal and hydro values represent winter ratings

Summer Peak	11,446	11,941
Winter Peak	12,086	12,879

Note: Median peak demand across all weather years

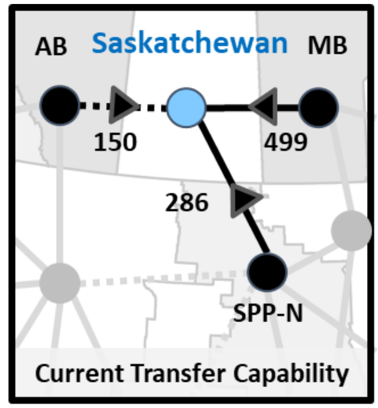
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
11/2 WY2012	Winter	11,849	6	2.0	519
12/27 WY2021	Winter	12,836	10	2.6	619
12/1 WY2022	Winter	12,852	7	3.7	764
12/2 WY2022	Winter	12,752	10	3.5	714

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

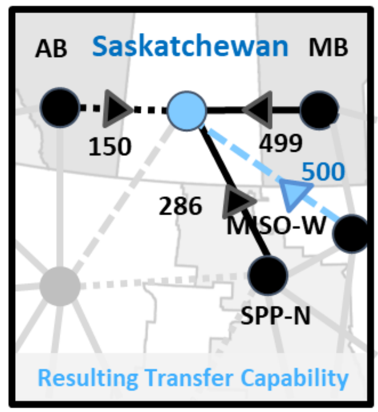
Saskatchewan

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Additions (MW)	Resulting Summer (MW)	Resulting Winter (MW)
Manitoba to Saskatchewan	306	499	0	306	499
MISO-W to Saskatchewan	Cand.	Cand.	500	500	500
SPP-N to Saskatchewan	370	286	0	370	286
Wasatch Front to Saskatchewan	Cand.	Cand.	0	0	0
Alberta to Saskatchewan	150	150	0	150	150
Total Import Interface Limit	**754**	**743**	**500**	**1,254**	**1,243**
Total Import Interface Limit + dc-only Interfaces Limit	**904**	**893**	**500**	**1,404**	**1,393**
(as % of 2033 Seasonal Peak)	**23%**	**21%**		**36%**	**32%**

Note: Alternate allocation of additional transfer capability to other neighbors may also resolve the identified deficiencies.



Existing interface
Existing dc-only interface
New Interface
Existing non-neighboring interface
Transfer capability addition



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	311	57	543	13.4
Iteration 1	181	120	28	353	4.6
Iteration 2	181	49	7	121	0.5
Iteration 3	181	23	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	3,725	4,248
Hydro	867	867
Variable Renewable	697	942
Energy Limited	67	127
Total	5,356	6,184

Note: Thermal and hydro values represent winter ratings

Summer Peak	3,517	3,951
Winter Peak	3,873	4,326

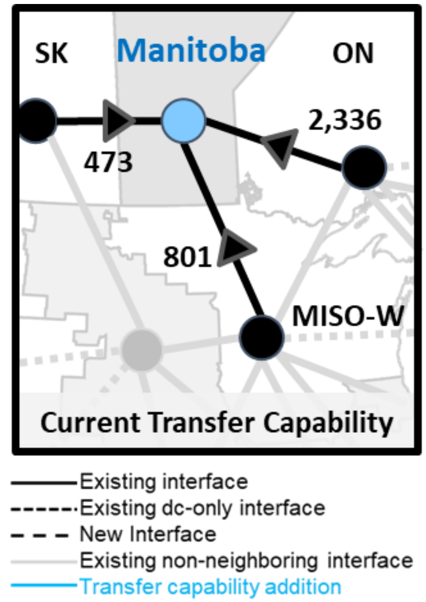
Note: Median peak demand across all weather years

Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
8/30 WY2007	Summer	3,776	8	2.1	447
9/4 WY2007	Summer	3,923	6	2.0	543
10/16 WY2009	Summer	3,732	11	2.3	397
8/30 WY2011	Summer	3,565	9	2.4	413
9/6 WY2011	Summer	3,687	2	0.1	81
9/10 WY2011	Summer	3,816	13	4.0	529
9/25 WY2011	Summer	3,833	2	0.1	42
11/17 WY2013	Winter	3,940	6	0.5	116

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

Manitoba

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Additions (MW)**	**Resulting Summer (MW)**	**Resulting Winter (MW)**
Ontario to Manitoba	1,961	2,336	N/A	N/A	N/A
MISO-W to Manitoba	0	801	N/A	N/A	N/A
Saskatchewan to Manitoba	106	473	N/A	N/A	N/A
Total Import Interface Limit	**1,961**	**2,483**			
Total Import Interface Limit + dc-only Interfaces Limit	**1,961**	**2,483**			
(as % of 2033 Seasonal Peak)	**61%**	**48%**			



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	0	0	0	0.0
Iteration 1	N/A	0	0	0	0.0
Iteration 2	N/A	0	0	0	0.0
Iteration 3	N/A	0	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	278	278
Hydro	6,200	6,433
Variable Renewable	301	349
Energy Limited	0	0
Total	6,779	7,060

Note: Thermal and hydro values represent winter ratings

Summer Peak	2,993	3,193
Winter Peak	4,657	5,205

Note: Median peak demand across all weather years

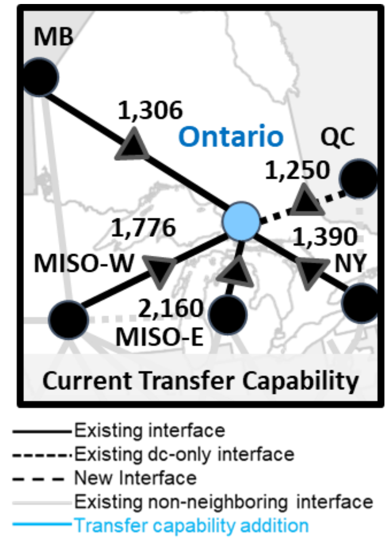
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
No identified resource deficiency events					

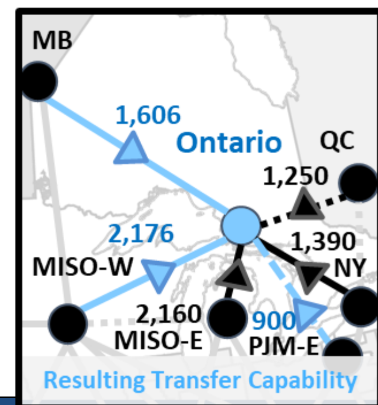
Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

Ontario

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Additions (MW)**	**Resulting Summer (MW)**	**Resulting Winter (MW)**
Québec to Ontario	1,250	1,250	0	1,250	N/A
Manitoba to Ontario	1,306	2,206	300	1,606	N/A
MISO-E to Ontario	2,160	2,081	0	2,160	N/A
MISO-W to Ontario	1,776	2,163	400	2,176	N/A
New York to Ontario	1,390	1,780	0	1,390	N/A
PJM-E to Ontario	Cand.	Cand.	900	900	N/A
Total Import Interface Limit	**2,160**	**2,206**	**1,600**	**3,760**	
Total Import Interface Limit + dc-only Interfaces Limit	**3,410**	**3,456**	**1,600**	**5,010**	
(as % of 2033 Seasonal Peak)	**13%**	**13%**		**19%**	

Note: Alternate allocation of additional transfer capability to other neighbors may also resolve the identified deficiencies.





Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	986	23	3,083	20.8
Iteration 1	1,027	300	3	619	1.2
Iteration 2	1,027	90	0	0	0.0
Iteration 3	1,027	85	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	21,010	20,609
Hydro	8,747	8,747
Variable Renewable	7,593	7,593
Energy Limited	810	1,825
Total	38,160	38,774

Note: Thermal and hydro values represent winter ratings

Summer Peak	23,626	26,782
Winter Peak	22,885	26,514

Note: Median peak demand across all weather years

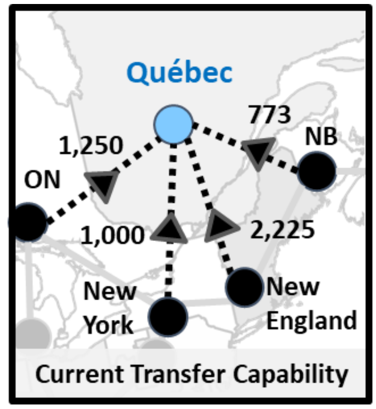
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
7/21 WY2009	Summer	26,517	1	0.2	155
8/4 WY2011	Summer	27,279	6	10.8	3,083
8/29 WY2013	Summer	27,493	5	5.2	1,591
7/8 WY2020	Summer	26,936	3	0.8	385
7/9 WY2020	Summer	27,340	4	3.4	1,358
7/10 WY2020	Summer	26,668	2	0.3	307
9/5 WY2023	Summer	26,282	2	0.2	147

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

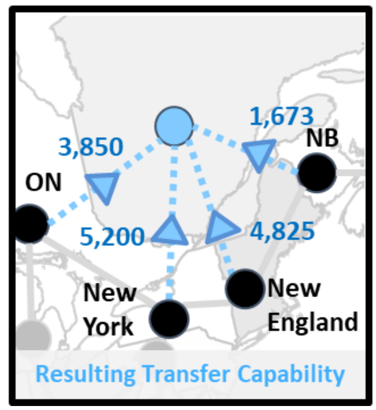
Québec

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Additions (MW)**	**Resulting Summer (MW)**	**Resulting Winter (MW)**
Ontario to Québec	1,250	1,250	2,600	N/A	3,850
New England to Québec	2,225	2,225	2,600	N/A	4,825
New Brunswick to Québec	742	773	900	N/A	1,673
New York to Québec	1,000	1,000	4,200	N/A	5,200
Total Import Interface Limit	N/A	N/A	N/A		N/A
Total Import Interface Limit + dc-only Interfaces Limit	**5,217**	**5,248**	**10,300**		**15,548**
(as % of 2033 Seasonal Peak)	**18%**	**11%**			**33%**

Note: Alternate allocation of additional transfer capability to other neighbors may also resolve the identified deficiencies.



Existing interface
Existing dc-only interface
New Interface
Existing non-neighboring interface
Transfer capability addition



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	4766	379	10,374	980.9
Iteration 1	3,454	1584	38	7,603	144.1
Iteration 2	3,454	376	16	4,879	37.1
Iteration 3	3,454	182	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	806	699
Hydro	39,046	39,429
Variable Renewable	3,874	4,882
Energy Limited	4,452	5,389
Total	48,178	50,399

Note: Thermal and hydro values represent winter ratings

Summer Peak	22,466	28,807
Winter Peak	40,737	47,820

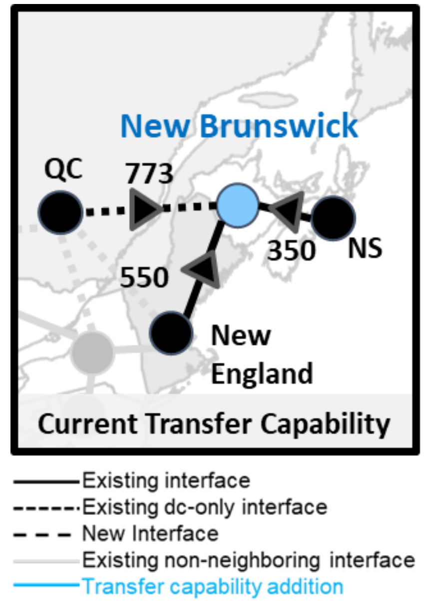
Note: Median peak demand across all weather years

Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
1/30 WY2007	Winter	51,110	19	56.8	7,168
12/15 WY2007	Winter	51,122	11	77.3	8,113
1/22 WY2008	Winter	47,594	10	32.2	5,498
1/25 WY2008	Winter	48,897	14	25.0	4,984
12/21 WY2008	Winter	47,250	13	35.0	4,793
1/15 WY2009	Winter	47,450	11	23.8	3,815
1/23 WY2009	Winter	46,963	10	25.8	4,538
1/29 WY2009	Winter	47,868	12	18.0	4,397
2/3 WY2012	Winter	47,772	12	19.5	4,717
2/27 WY2012	Winter	46,106	6	14.1	3,973
1/18 WY2013	Winter	49,370	13	36.5	5,210
12/24 WY2013	Winter	46,325	9	17.9	3,678
12/30 WY2013	Winter	49,194	13	22.7	4,958
12/31 WY2013	Winter	48,535	15	52.4	6,166
1/19 WY2019	Winter	46,737	10	27.8	4,329
1/22 WY2022	Winter	47,115	10	20.7	4,554
1/24 WY2022	Winter	48,492	10	20.2	4,035
1/27 WY2022	Winter	48,250	8	12.4	3,718
2/3 WY2023	Winter	52,036	13	93.5	9,356
2/4 WY2023	Winter	51,874	24	139.1	10,374
Top 20 events listed. Additional 24 events...			136	209.9	3,525

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

New Brunswick

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Additions (MW)	Resulting Summer (MW)	Resulting Winter (MW)
Québec to New Brunswick	742	773	N/A	N/A	N/A
New England to New Brunswick	550	550	N/A	N/A	N/A
Nova Scotia to New Brunswick	350	350	N/A	N/A	N/A
Total Import Interface Limit	**900**	**900**			
Total Import Interface Limit + dc-only Interfaces Limit	**1,642**	**1,673**			
(as % of 2033 Seasonal Peak	**73%**	**39%**			



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	372	5	118	0.2
Iteration 1	N/A	244	5	545	1.4
Iteration 2	N/A	94	9	668	3.8
Iteration 3	N/A	63	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	3,200	3,194
Hydro	968	968
Variable Renewable	809	1,187
Energy Limited	165	178
Total	5,142	5,527

Note: Thermal and hydro values represent winter ratings

Summer Peak	2,216	2,252
Winter Peak	3,880	4,245

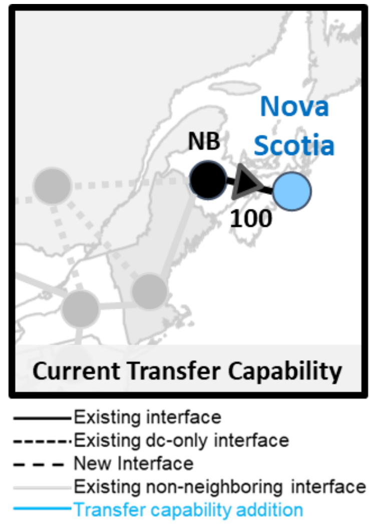
Note: Median peak demand across all weather years

Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
2/4 WY2023	Winter	4,628	5	0.2	118

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

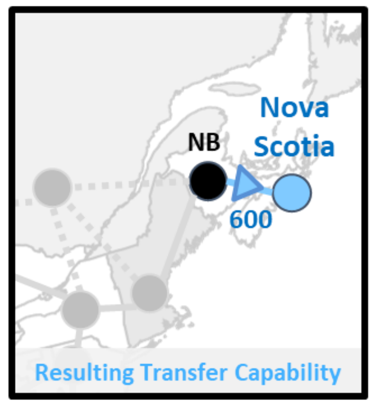
Nova Scotia

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Additions (MW)	Resulting Summer (MW)	Resulting Winter (MW)
New Brunswick to Nova Scotia	170	100	500	670	600
Total Import Interface Limit	**170**	**100**	**500**	**670**	**600**
Total Import Interface Limit + dc-only Interfaces Limit	**170**	**100**	**500**	**670**	**600**
(as % of 2033 Seasonal Peak)	**12%**	**4%**		**45%**	**22%**



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	2,762	641	582	86.7
Iteration 1	194	1,195	131	438	14.8
Iteration 2	194	412	21	438	3.8
Iteration 3	194	293	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years



Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	1,993	1,993
Hydro	405	405
Variable Renewable	668	1,402
Energy Limited	101	109
Total	3,167	3,909

Note: Thermal and hydro values represent winter ratings

Summer Peak	1,444	1,477
Winter Peak	2,430	2,674

Note: Median peak demand across all weather years

Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
1/28 WY2007	Winter	2,405	9	2.3	405
12/13 WY2007	Winter	2,703	10	2.2	341
12/14 WY2007	Winter	2,470	16	4.1	558
12/22 WY2007	Winter	2,512	13	2.2	343
1/24 WY2008	Winter	2,372	15	3.9	547
12/15 WY2009	Winter	2,224	14	2.6	353
12/19 WY2009	Winter	2,345	17	4.4	466
12/9 WY2010	Winter	2,367	15	3.8	462
1/6 WY2011	Winter	2,350	16	3.0	496
2/3 WY2011	Winter	2,206	7	1.4	383
12/4 WY2012	Winter	2,095	7	1.6	358
12/17 WY2012	Winter	2,469	5	0.9	351
12/21 WY2012	Winter	2,155	10	1.6	413
1/6 WY2013	Winter	2,756	5	1.3	369
10/30 WY2013	Summer	1,723	16	2.5	370
12/3 WY2013	Winter	1,934	9	1.1	338
12/14 WY2013	Winter	2,594	10	2.3	351
12/17 WY2013	Winter	2,543	9	2.8	582
12/10 WY2021	Winter	2,371	10	1.3	379
2/4 WY2023	Winter	3,021	21	4.0	438
Top 20 events listed. Additional 105 events…			407	37.6	319

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

Chapter 9: Future Work

While this study represents a pioneering and comprehensive effort to evaluate transfer capability into and within Canada and its impact on energy adequacy, it also had limitations. These factors highlight the need for additional work to build on the findings and address areas not fully explored in this initial analysis. The following sections outline key areas for future work that will help refine and expand the understanding of transfer capability and its role in strengthening grid reliability.

Other future work highlighted in the ITCS study that also applies to the Canadian Analysis is listed as follows:

- Explore alternative resource mixes
- Expand weather datasets
- Evaluate stability and transfer capability during extreme weather events
- Incorporate probabilistic resource adequacy analysis
- Establish study periodicity and parameters

Expand Use of Data Reporting Systems

All entities were very responsive to data requests throughout the study process. However, NERC noted several areas of improvement:

- The compilation of outage data was more complicated and time-intensive for provinces not already submitting generator outage data into the NERC GADS system. The study team recommends that these entities expand their use of the GADS, thus simplifying future studies.
- The hourly energy and resource profile data was not publicly available and special data requests were sent to Planning Coordinators in Canada to collect the required data. Publicly available energy information data (similar to Energy Information Administration form 930 data) for Canadian entities, spanning several historical years (5–10 years), would be very beneficial for future studies for NERC and for other interested entities that perform energy analysis of the Canadian systems, such as consultants and academic institutions.
- The study team observed inconsistent reporting of resource forecast data for NERC's LTRA. Resource forecasts involve significant uncertainty, especially 5–10 years into the future. To deal with this uncertainty, it is helpful to analyze risks under various resource development scenarios. For example, analysis of energy deficiency risks under optimistic and conservative resource development scenarios could provide a range that might be very helpful for decision-makers and stakeholders. To help facilitate such analysis, NERC encourages all planning entities to consistently report resource forecasts for all types of resources in different stages of development (Tier 1, Tier 2, etc.).

Harmonizing Path Limits and Transfer Capability Calculations

As noted earlier in the report, many entities use path limits, some of which may differ significantly from the transfer capability results included in this report. While each is valid, the use of both methods could confuse some readers. The team recommends further discussions to determine the best way to optimize future continent-wide studies.

Chapter 10: Acknowledgements

NERC appreciates the people across the industry who provided technical support and identified areas for improvement throughout the Canadian Analysis.

Table 10.1: NERC Industry Group Acknowledgements	
Group	**Members**
Advisory Group	Gabriel Adam (IESO), Yves Albert (New Brunswick Power), Aaron Berner (PJM), Margaret Albright (BPA), Casey Cathey (SPP), Bryce Clothier (Nova Scotia Power), Jessica Cockrell (FERC), Ganesh Doluweera (Régie de l'énergie du Canada / Canada Energy Regulator), Laurentia Dumitresco (Régie de l'énergie du Canada / Canada Energy Regulator), Robert Entriken (EPRI), Vincent Fihey (Hydro Québec), Greg Ford (Georgia System Operations), Tom Galloway (NATF), Jeffrey Gindling (Duke Energy Midwest), Prabhu Gnanam (ERCOT), Biju Gopi (California ISO), Wayne Guttormson (SaskPower), Hassan Hayat (AEP), Matt Holtz (Invenergy), Larre Hozempa (FirstEnergy), Faheem Ibrahim (ISO New England), David Jacobson (Manitoba Hydro), Brett Kruse (Calpine), Brad Little (Natural Resources Canada), Charles Long (Entergy), Chelsea Loomis (Northern Grid), Christopher Mclean (California Energy Commission), David Meyer (Puget Sound Energy), Gayle Nansel (WAPA), Ryan Sackett (DOE), Zachary Smith (NYISO), Lance Spross (ONCOR), Mark Tremblay (Eversource), Guihua Wang (BC Hydro), Eric Wu (AESO)
Industry Consultants	Dave Angell, Paul Choudhury, Robert Kondziolka, Gary Leidich
Transfer Study Team	Salva Andiappan (MRO), Diana Barsotti (NPCC), Kent Bolton (WECC), Edwin Cano (PowerGem), Bryan Clark (MRO), Vic Howell (WECC), John Idzior (RF), Marilyn Jayachandran (NERC), Gaurav Karandikar (SERC), Neeraj Lal (NPCC), Matthew A. Lewis (NERC), Saad Malik (NERC), Shirley Mathew (Texas RE), Melinda Montgomery (SERC), John Moura (NERC), Manos Obessis (PowerGem), Mohamed Osman (NERC), Shayan Rizvi (NPCC), Kevin Sherd (NERC), Paul Simoneaux (SERC), Doug Tucker (WECC), Dianlong Wang (MRO), Brad Woods (Texas RE)
SAMA Team (Scenarios, Assumptions, Metrics, and Adequacy)	Salva Andiappan (MRO), Diana Barsotti (NPCC), Richard Becker (SERC), Kent Bolton (WECC), Ryan Deyoe (Telos Energy), Matthew Elkins (WECC), Johnny Gest (RF), Vic Howell (WECC), Marilyn Jayachandran (NERC), Bill Lamanna (NERC), Matthew A Lewis (NERC), Saad Malik (NERC), William Martin (NERC), Shirley Mathew (Texas RE), John Moura (NERC), Jack Norris (NERC), Mark Olson (NERC), Mohamed Osman (NERC), Matt Richwine (Telos Energy), Katie Rogers (WECC), Martin Sas (SERC), Kevin Sherd (NERC), Paul Simoneaux (SERC), Derek Stenclik (Telos Energy), Jim Uhrin (RF), Brad Woods (Texas RE)
Report Writing Team	Diana Barsotti (NPCC), Candice Castaneda (NERC), Bryan Clark (MRO), Mark Henry (Texas RE), Saad Malik (NERC), Stony Martin (SERC), Kevin Sherd (NERC), Robert Tallman (NERC), Jim Uhrin (RF), Brad Woods (Texas RE)

Appendix A: Data Sources

The data sources used for the energy margin analysis are shown in **Table A.1** below.

Table A.1: Overview of the Two-Pronged Approach for Historical Weather Data		
	Synthetic Weather Data Weather Years 2007–2013	**Scaled Historic Actuals Weather Years 2019–2023**
Load Profiles	Resampling of historical load data from 2019–2023 was performed based on temperature observations and day of week.	Historical demand from 2019–2023 provided by Canadian utilities was scaled to meet a future peak and energy target.
Wind and solar profiles	Simulated power production profiles for wind and solar resources captured geographic diversity based on new site selection and made assumptions on technology developments. Wind data used the NREL WindToolkit and Solar data used the NREL National Solar Radiation Database (NSRDB).	The actual historical generation from wind resources, provided by Canadian utilities, was linearly scaled to align with future wind capacity levels. Due to a relatively small installed solar fleet, simulated solar generation from the NREL National Solar Radiation Database (NSRDB) data was also used for 2019–2023 weather years.
Forced outages	Forced outages from the 2019–2023 period were resampled based on season and temperature observations.	Historical daily forced outage rates provided by the Canadian utilities from 2019–2023 aggregated by province and fuel type.
Planned outage	Historical planned outage schedules from the 2019–2023 period were reused in earlier weather years.	Historical daily planned outage rates provided by the Canadian utilities from 2019–2023 aggregated by province and fuel type.

Appendix B: Load Profiles

Target Forecast (2023 LTRA Annual Energy, Summer and Winter Peak Loads)

Historical hourly load provided by the Canadian utilities from 2019 to 2023 served as the foundational dataset used to simulate the 2019–2023 weather years and to estimate load for the synthetic 2007–2013 weather years. The target forecast for the study used the 2023 LTRA seasonal peak load and annual energy forecasts for 2024 and 2033 and assumed that these values represent the median forecast (P50). Based on this assumption, the 2019–2013 historical hourly loads provided by the Canadian utilities were scaled so that the median peak and energy values of those datasets matched the values for each LTRA assessment area.[83] The data provided in the LTRA forecast represents net energy for load, which excludes the impacts of BTM PV. BTM PV was modeled as a supply-side resource for the energy margin analysis, so the LTRA forecast was adjusted to gross load derived from BTM PV assumptions in the LTRA. The target peak and energy forecasts for each LTRA assessment area used in this study are shown in **Table B.1**.

Table B.1. LTRA Forecast Target Annual Energy and Summer/Winter Peak Loads

Year	Period	BC	AB	SK	MB	ON	QC	NB	NS
2024	Summer Peak (MW)	8,961	11,446	3,517	2,993	23,626	22,466	2,216	1,444
	Winter Peak (MW)	11,938	12,086	3,873	4,657	22,885	40,737	3,880	2,430
	Annual Energy (GWh)	66,350	87,975	25,771	24,653	139,492	197,724	17,034	11,524
2033	Summer Peak (MW)	9,897	11,941	3,951	3,193	26,782	28,807	2,252	1,477
	Winter Peak (MW)	12,970	12,879	4,326	5,205	26,514	47,820	4,245	2,674
	Annual Energy (GWh)	72,898	94,899	28,866	26,927	172,385	223,477	17,706	11,837

For the synthetic load years (2007–2013), data from the scaled historical weather years (2019–2023) was resampled based on temperature observations in 2007–2013. Temperature observations were taken from Canadian airports and averaged based on population. For each season, a similar temperature day was randomly sampled from the 2019–2023 period and adjusted based on the day of the week. No adjustments were made for temperature observations outside of the historical record. For example, if a cold period in 2007–2013 was colder than any observation in the 2019–2023 period, no adjustments were made to extrapolate load data. Note that the Alberta synthetic load data was provided by AESO.

The synthetic and historical load profiles were scaled to align the median energy and peak loads from the weather years to the targets at the LTRA assessment area level.

Annual peak loads for each TPR by weather year are shown in **Table B.2** and **Table B.3** below for the 2024 and 2033 cases, respectively. Finally, **Figure B.1** and **Figure B.2** illustrate the variability in peak loads relative to the median demand for each of the Canadian TPRs. Annual peak loads vary due to the underlying weather conditions present for each TPR in each weather year. Minimum, median, and maximum annual peak load values are provided as a summary. Load reflects the net energy for load, which excludes BTM PV.

[83] See https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf, appendix B, for more information on scaling of weather year loads.

Table B.2: Annual Peak Load by Weather Year (2024 Case)															
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Min	Median	Max
British Columbia	11,961	11,914	12,188	12,062	12,032	12,157	11,693	11,385	11,738	12,334	11,863	11,584	11,385	11,938	12,334
Alberta	12,633	12,198	12,164	12,173	12,886	12,639	12,218	11,998	12,852	11,995	12,202	11,866	11,866	12,200	12,886
Saskatchewan	3,926	3,848	3,866	3,926	3,898	3,881	3,880	3,791	3,838	3,927	3,744	3,619	3,619	3,873	3,927
Manitoba	4,559	4,663	4,752	4,650	4,603	4,765	4,748	4,760	4,603	4,774	4,536	4,625	4,536	4,657	4,774
Ontario	24,223	22,963	23,526	24,616	24,127	24,088	24,341	21,963	24,226	22,936	21,949	23,131	21,949	23,807	24,616
Québec	46,115	41,553	40,775	39,344	40,634	40,698	41,906	40,641	39,443	37,826	41,242	43,996	37,826	40,737	46,115
New Brunswick	4,064	3,864	3,869	3,700	3,983	3,999	4,237	3,749	3,578	3,601	3,890	4,349	3,578	3,880	4,349
Nova Scotia	2,492	2,370	2,401	2,403	2,534	2,510	2,756	2,457	2,360	2,297	2,371	2,763	2,297	2,430	2,763

Table B.3: Annual Peak Load by Weather Year (2033 Case)															
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Min	Median	Max
British Columbia	12,837	13,472	13,441	12,749	12,989	13,616	12,758	12,578	12,950	13,598	13,085	12,792	12,578	12,970	13,616
Alberta	13,336	12,853	12,680	12,852	13,349	13,343	12,883	12,681	13,611	12,683	12,871	12,548	12,548	12,862	13,611
Saskatchewan	4,371	4,293	4,311	4,371	4,343	4,326	4,325	4,324	4,371	4,468	4,272	4,140	4,140	4,326	4,468
Manitoba	5,096	5,211	5,304	5,199	5,148	5,321	5,303	5,316	5,148	5,330	5,074	5,171	5,074	5,205	5,330
Ontario	27,375	26,433	27,009	27,773	27,279	27,242	27,493	26,315	27,340	26,095	26,299	26,647	26,095	27,126	27,773
Québec	51,122	48,897	47,868	46,056	47,683	47,772	49,370	47,749	46,187	44,117	48,492	52,036	44,117	47,820	52,036
New Brunswick	4,461	4,206	4,253	4,054	4,368	4,363	4,237	4,121	3,936	3,886	4,270	4,628	3,886	4,245	4,628
Nova Scotia	2,733	2,611	2,643	2,613	2,796	2,756	2,756	2,704	2,598	2,530	2,610	3,021	2,530	2,674	3,021

Figure B.1: Weather-Year Variation Relative to Median Peak Load

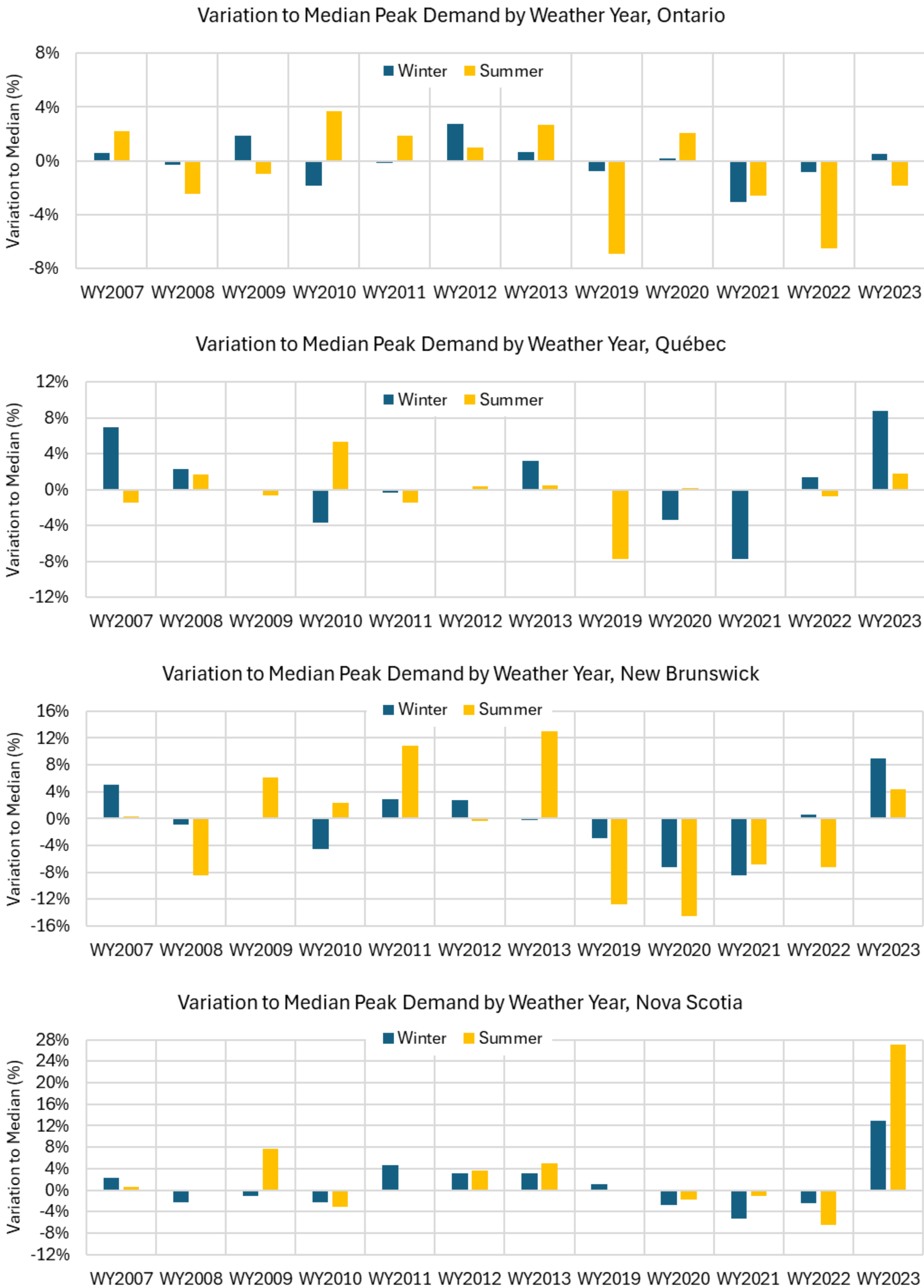


Figure B.2: Weather-Year Variation Relative to Median Peak Load (continued)

Appendix C: 2024 and 2033 Capacities

Table C.1 details the capacity in each TPR by resource type in the 2024 case, based on the 2023 LTRA Form B submissions and adjustments provided by Canadian utilities. **Table C.2** shows the capacity of certain retirements and Tier 1 additions that were applied to the 2033 case. **Table C.3** lists the total capacity by resource type and TPR in the 2033 case, and **Table C.4** provides the total capacity used in the sensitivity to align capacity reported in the 2024 LTRA. In each of these four tables, the winter capacity is shown for thermal and hydro resources and the installed capacity for wind, solar, and storage resources.

Table C.1: 2024 Capacity by Resource Type and TPR (in MW)

Transmission Planning Region	Coal	Natural Gas	Oil	Nuclear	Other	Hydro	Wind	Utility-Scale Solar	Distrib. Solar	Pumped Storage	Battery Storage	Demand Response
British Columbia	0	437	0	0	447	16,710	747	17	0	0	0	0
Alberta	0	14,094	0	0	444	894	5,688	1,812	142	0	190	0
Saskatchewan	1,390	2,310	0	0	25	867	615	37	45	0	0	67
Manitoba	0	278	0	0	0	6,200	259	0	42	0	0	0
Ontario	0	8,071	2,107	10,533	299	8,747	4,943	478	2,172	175	0	635
Québec	0	0	429	0	377	39,046	3,820	10	62	0	0	4,452
New Brunswick	466	298	1,598	671	167	968	595	132	82	0	0	165
Nova Scotia	1,229	462	231	0	401	405	613	5	50	0	0	101
Total Canada	**3,085**	**25,950**	**4,365**	**11,204**	**2,160**	**73,837**	**17,280**	**2,491**	**2,595**	**175**	**190**	**5,420**

Table C.2: Tier 1 Additions and Certain Retirements by Resource Type and TPR (in MW)

Transmission Planning Region	Coal	Natural Gas	Oil	Nuclear	Other	Hydro	Wind	Utility-Scale Solar	Distrib. Solar	Pumped Storage	Battery Storage	Demand Response
British Columbia		-383				778						
Alberta		378					446	2,871	375		273	
Saskatchewan		544			-21		190	10	45		60	
Manitoba						233			48			
Ontario		660		-1,061							1,015	
Québec					-107	383	334		656			937
New Brunswick			-6						378			13
Nova Scotia							502		232			8
Total Canada		**1,199**	**-6**	**-1,061**	**-128**	**1,394**	**1,472**	**2,881**	**1,734**		**1,348**	**958**

Table C.3: 2033 Capacity by Resource Type and TPR (in MW)

Transmission Planning Region	Coal	Natural Gas	Oil	Nuclear	Other	Hydro	Wind	Utility-Scale Solar	Distrib. Solar	Pumped Storage	Battery Storage	Demand Response
British Columbia	0	54	0	0	447	17,488	747	17	0	0	0	0
Alberta	0	14,472	0	0	444	894	6,134	4,683	517	0	463	0
Saskatchewan	1,390	2,854	0	0	4	867	805	47	90	0	60	67
Manitoba	0	278	0	0	0	6,433	259	0	90	0	0	0
Ontario	0	8,731	2,107	9,472	299	8,747	4,943	478	2,172	175	1,015	635
Québec	0	0	429	0	270	39,429	4,154	10	718	0	0	5,389
New Brunswick	466	298	1,592	671	167	968	595	132	460	0	0	178
Nova Scotia	1,229	462	231	0	401	405	1,115	5	282	0	0	109
Total Canada	**3,085**	**27,149**	**4,359**	**10,143**	**2,032**	**75,231**	**18,752**	**5,372**	**4,329**	**175**	**1,538**	**6,378**

Table C.4: 2033 Capacity by Resource Type and TPR, 2024 LTRA Sensitivity (in MW)

Transmission Planning Region	Coal	Natural Gas	Oil	Nuclear	Other	Hydro	Wind	Utility-Scale Solar	Distrib. Solar	Pumped Storage	Battery Storage	Demand Response
British Columbia	0	444	0	0	658	17,488	776	17	0	0	0	0
Alberta	0	14,472	0	0	444	894	6,134	4,683	517	0	463	0
Saskatchewan	1,390	2,854	0	0	32	867	805	47	93	0	60	67
Manitoba	0	278	0	0	0	6,488	259	0	128	0	0	0
Ontario	0	8,930	2,107	11,415	302	8,747	4,943	478	2,172	175	2,967	1,535
Québec	0	0	429	0	400	39,354	7,818	10	718	0	0	5,389
New Brunswick	466	698	1,577	663	167	968	662	186	467	0	0	197
Nova Scotia	1,229	462	231	0	71	405	1,231	5	287	0	150	120
Total Canada	**3,085**	**28,138**	**4,344**	**12,078**	**2,074**	**75,211**	**22,628**	**5,426**	**4,382**	**175**	**3,640**	**7,308**

Table C.5 provides the monthly hydro rating factors as a percentage of capacity.

Table C.5: Monthly Maximum Rating Factors for Hydro Resources by TPR (% of Capacity)												
Transmission Planning Region	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
British Columbia	70.04	70.04	70.04	70.04	70.04	70.04	70.04	70.04	70.04	70.04	70.04	70.04
Alberta	38.89	36.43	32.87	40.03	52.12	72.64	68.19	59.28	54.72	38.61	39.60	43.43
Saskatchewan	53.81	53.40	49.31	58.79	52.29	70.76	67.10	49.32	41.18	43.21	43.09	47.13
Manitoba	87.59	86.10	85.42	83.67	85.95	84.30	85.34	86.87	83.40	78.26	82.76	85.92
Ontario	71.95	70.29	65.18	67.85	70.07	66.58	63.48	60.80	56.76	59.34	64.85	66.52
Québec	95.05	95.05	95.05	95.05	95.05	95.05	95.05	95.05	95.05	95.05	95.05	95.05
New Brunswick	72.26	61.16	64.79	84.60	87.11	70.28	60.45	47.18	51.71	69.88	76.93	76.88
Nova Scotia	71.68	75.24	69.59	62.86	69.94	57.31	49.69	24.62	31.34	33.32	48.04	53.27

Appendix D: Iteration-Specific Information

This section provides additional iteration-specific detail for each province with identified resource deficiencies.

Alberta

Table D.1: Finalizing Transfer Capability Additions to Alberta				
Iteration	**Transfer Capability Additions (MW)**			**Max Resource Deficiency (MW)**
	British Columbia	**Wasatch Front**	**Saskatchewan**	
Base				764
Iteration 1	15	43	197	510
Iteration 2	21	63	171	135
Iteration 3	16	46	73	0
Total	52	152	441	
Rounded	**0**	**0**	**600**	

The size of Iteration 3 was prorated based on the maximum remaining deficiency. Additionally, during the final rounding step, small transfer capability additions were reallocated to other interfaces pro rata until the minimum addition size of 300 MW was reached. Alternate allocations of transfer capability were found to be effective in addressing the identified deficiencies.

Saskatchewan

Table D.2: Finalizing Transfer Capability Additions to Saskatchewan						
Iteration	**Transfer Capability Additions (MW)**					**Max Resource Deficiency (MW)**
	Alberta	**Wasatch Front**	**SPP North**	**MISO West**	**Manitoba**	
Base						543
Iteration 1	33	36	36	48	28	353
Iteration 2	29	34	37	55	26	121
Iteration 3	17	20	25	45	15	0
Total	79	90	98	148	69	
Rounded	**0**	**0**	**0**	**500**	**0**	

The size of Iteration 3 was prorated based on the maximum remaining deficiency. Additionally, during the final rounding step, small transfer capability additions were reallocated to other interfaces pro rata until the minimum addition size of 300 MW was reached. Alternate allocations of transfer capability may also be effective in addressing the identified deficiencies.

Ontario

Table D.3: Finalizing Transfer Capability Additions to Ontario							
Iteration	Transfer Capability Additions (MW)						Max Resource Deficiency (MW)
	Manitoba	MISO West	MISO East	PJM East	New York	Québec	
Base							3,083
Iteration 1	169	207	0	469	32	150	619
Iteration 2	86	141	0	316	14	59	0
Total	255	348	0	785	46	209	
Rounded	300	400	0	900	0	0	

Only two iterations were required, and the size of Iteration 2 was prorated based on the maximum remaining deficiency. Additionally, during the final rounding step, small transfer capability additions were reallocated to other interfaces pro rata until the minimum addition size of 300 MW was reached. Alternate allocations of transfer capability may also be effective in addressing the identified deficiencies.

Québec

Table D.4: Finalizing Transfer Capability Additions to Québec					
Iteration	Transfer Capability Additions (MW)				Max Resource Deficiency (MW)
	New York	New England	Ontario	New Brunswick	
Base					10,374
Iteration 1	1,045	941	785	682	7,603
Iteration 2	1,431	986	852	186	4,879
Iteration 3	1,711	710	984	50	0
Total	4,187	2,637	2,621	918	
Rounded	4,200	2,600	2,600	900	

This is the same information as in **Table 5.3** provided earlier in the report but is provided here for completeness. Alternate allocations of transfer capability may also be effective in addressing the identified deficiencies.

Nova Scotia

Table D.5: Finalizing Transfer Capability Additions to Nova Scotia		
Iteration	Transfer Capability Additions (MW)	Max Resource Deficiency (MW)
	New Brunswick	
Base		582
Iteration 1	194	438
Iteration 2	194	85
Iteration 3	85	0
Total	473	
Rounded	500	

The size of Iteration 3 was prorated based on the maximum remaining deficiency.