NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

ITCS SAMA[1] Study Scope – Part 2

August 2024

Background

Part 1 of the Interregional Transfer Capability Study (ITCS) will include conventional transmission planning and will use a narrow set of planning cases to evaluate transfer capability using "Summer Peak" and "Winter Peak" power flow cases. These power flow cases reflect only a limited number of snapshots in time, referred to as dispatch conditions, and may not represent extreme conditions that may jeopardize grid reliability. Using the Part 1 transfer capability results, Part 2 of the ITCS, referred to as "Prudent Additions Recommendations," seeks to:

- Identify system conditions under which the system could experience energy shortfalls,
- Determine potential increases to interregional transfer capability for each Transmission Planning Region (TPR), and
- Evaluate which TPR(s) are prudent to add increased transfer capability.

Purpose

The Part 2 study scope consists of three parts that will meet the objectives below. This scoping document is intended to provide key inputs and assumptions primarily for Part 2 of the ITCS – to identify prudent additions to transfer capability.

1. Develop a North American dataset of consistent, correlated, time-synchronized load, wind, solar, and weather-dependent outages,
2. Identify periods of tight supply conditions and potential energy shortfalls that can be used to quantify prudent additions of interregional transfer capability (i.e., energy assessment), and
3. Develop metrics and methods to identify which pairs of TPRs should be prioritized for increased interregional transfer capability.

Specifically not in-scope:

This scope of work will specifically not address the following items, which should be addressed in subsequent modeling and planning efforts.

- Probabilistic resource adequacy analysis – the ITCS is not trying to conduct a North American resource adequacy assessment, but rather develop a screening tool for challenging periods and create assumptions to redispatch transmission planning cases based on representative weather conditions.
- Comparisons of interregional transfer capability against local generation additions for reliability.
- Identification of specific projects to increase transfer capability.

[1] Scenarios, Assumptions, Metrics, and Adequacy

- Developing prudent additions recommendations for deficiencies within Canada. This will be addressed in the Canadian Analysis.

Study Tool

The SAMA team will develop custom spreadsheet tools, augmented by python and other coding tools where necessary. The datasets can be used in subsequent modeling tools, including production cost modeling software.

Cases and Scenarios

The Part 2 analysis of the ITCS will evaluate several cases, system conditions, risk periods, and sensitivities. A definition of each of these terms is provided below.

- **Case:** Represents the overall system portfolio, including installed capacity (installations and retirements), annual load level, and transmission topology.
- **Scenario:** Assumptions around an operating condition, such as load level, generation, resource availability, and risk periods including the effects of weather.
- **Risk Periods:** Output identified from the assessment of cases under different scenarios where regions have low resource availability relative to load where reliability serving demand is at risk.
- **Sensitivity:** An adjustment to the underlying assumptions, typically made in isolation, to test the impact of a model parameter or input.

A case is the highest resolution, which can be composed of multiple scenarios, which can further be evaluated across multiple risk periods and sensitivities. Unlike the ITCS Part 1, which will evaluate only select scenarios, the ITCS Part 2 analysis will assess a wider range of these parameters.

To quantify existing transfer capability in Part 1, the NERC ITCS used typical Interconnection-wide cases that were built per the MOD-032 standard for the current system (1-year out) including two scenarios, “Summer Peak” and “Winter Peak.”

Table 1: Study Case and Scenario Matrix		
Study Cases		
Part 1 – Transfer Capability Analysis		
Study Scenarios	**Current System**	**10-Year Outlook**
Summer Peak	X	X
Winter Peak	X	X
Part 2 – Energy Assessment		
Cold Snap	X	X
Heat Wave	X	X
Renewable Drought	X	X
Other conditions not specified	X	X

Case Assumptions and Portfolios

Generation portfolios will be developed for both the current system (1-year out) and a 10-year outlook that are aligned, to the extent reasonable, with the MOD-032 Base Case power flows used in Part 1. For Part 2 of the analysis, generation portfolios will be derived from the 2023 NERC Long Term Reliability Assessment (LTRA), including similar representation for existing generators, retirements, Tier 1 and Tier 2 additions, and regional load forecasts.

The NERC LTRA generator and load data will be adjusted so that the study topology will align uniformly with the Part 1 ITCS Transfer Analysis. For example, the SPP NERC LTRA region will be divided into SPP-N and SPP-S so that the energy analysis can be conducted with the same regional breakdown as Part 1. Although ideally the cases would be consistent, it is important to note that given the differences between resource and transmission planning, some discrepancies between the Part 1 and Part 2 analysis are expected.

Scenario Assumptions

Once the Cases are developed, Scenario assumptions will use publicly available and NERC proprietary datasets to conduct the Part 2 energy assessment. Data will be compiled to create a multi-year, time-synchronized dataset of key properties that determine resource availability and energy margins by combining load, wind, solar, hydro, and weather-dependent outages of thermal resources.

Data Sources for Scenarios

There are two sources used to develop this dataset:

1. Historical measured data for load, wind, and solar from recent years, scaled appropriately to represent future conditions; **and/or,**
2. Synthetic datasets using historical weather observations (temperature, wind speed, solar irradiance, etc.) and estimated load and resource availability.

Error! Reference source not found. compares the benefits and limitations of the two sources, and the weather years for which they are used.

Table 2: Two types of data sources for Part 2 evaluation

	Source 1 Historical Measured Data (2019-2023)	Source 2 Synthetic Weather Data (2007-2013)
Data Source	Reported data from balancing authorities, including EIA-930 and FERC-714	North American meteorological datasets – often developed by National Labs, including National Solar Radiation Database (NSRDB), Wind Toolkit, etc.
Historical Record	Must use a shorter historical record, i.e. last 3-5 years to make sure it is representative of current system	Can span several weather years, typically 10-40 years, but current data gaps (specifically for wind resources) can limit years of analysis

Table 2: Two types of data sources for Part 2 evaluation		
	Source 1 Historical Measured Data (2019-2023)	**Source 2 Synthetic Weather Data (2007-2013)**
Outlier Events	Fewer outlier events will be in the sample size (i.e. Winter Storm Uri, Elliott, Heat Domes) but may be more accurate than synthetic data	Can get a longer history of outlier events (i.e. cold snaps in the 1980s) but estimates may be less accurate than recent observations.
Wind and solar scaling	Scaling historical generation amplifies correlation of resources and assumes technology remains constant	Captures geographic diversity based on new site selection and allows user to make assumptions on technology developments
Electrification Trends	Embedded in the underlying load data, cannot be easily introduced	Load data can be developed by end use to introduce changes from electric vehicles and building electrification.
Climate Trends	Embedded in the underlying data, cannot be easily introduced	Climate trends can be applied to underlying meteorological datasets
	Better for analyzing near-term power system during specific events.	**Better for analyzing future power system and/or screening across a wider range of potential events.**

Based on the years selected from the above data sources, the following significant weather events that are inherently included in the Part 2 analysis include the following:

- Intense Cold Wave, 2011
- Western Wide Area Heat Domes, 2020 and 2021
- Winter Storm Uri, 2021
- Winter Storm Elliott, 2022
- Western and Midwest Heat Waves, 2023
- SPP Wind Drought, 2023

Study Topology

Create all inputs and assumptions on the topology shown in Figure 1, which will align with the TPRs used in Part 1 to calculate transfer capability and should closely align with the LTRA.

In several instances FERC Order 1000 regions have been broken down into sub-regions for calculating the intra-regional transfer capability. This is because FERC Order 1000 regions are geographically very large, and it is more informative and comprehensive to calculate transfer capability at a sub-regional level because availability of resource mix, occurrence of correlated outages, and transmission capacity varies at a sub-regional level under various system conditions. In addition, the use of sub-region topologies allows NERC to recommend prudent additions between sub-regions by providing increased specificity to the overall analysis and to the recommendations that will follow the analysis. In other words, under certain conditions, resource and transmission limitations at a sub-regional level may be masked when evaluated at a larger FERC Order 1000 regional level. At the same time, sub-regions have been selected to be large enough that they only uncover broader reliability issues and that sub-regions are not so small that this study starts to uncover local transmission problems. The main purpose of this study is to look at broader intra-regional transmission transfer capability issues and not to address local transmission issues.

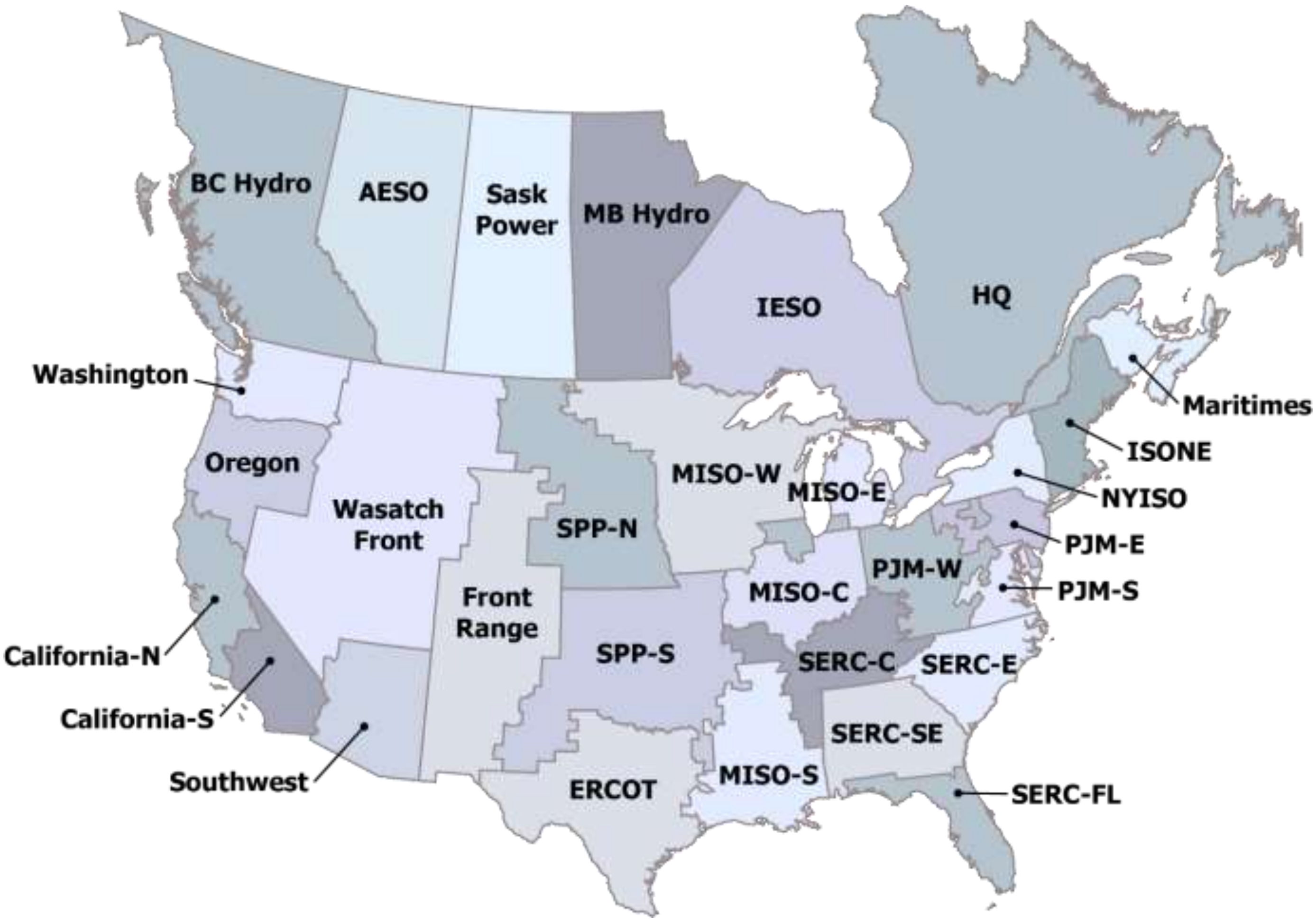


Figure 1: Transmission Planning Regions

Inputs and Assumptions

__Resource Mix:__ For portfolio details, including generator retirements and additions, see previous section on "Case Assumptions and Portfolios."

__Load:__ 8760 hourly loads across 12 weather years that change to reflect seasonality, weather impacts, day of week, etc. The ITCS will leverage historical loads from recent event (EIA-930) and synthetic load data from the National Renewable Energy Labs (NREL) Standard Scenario dataset (see **Error! Reference source not found.** for discussion of data sources). Both sources will be scaled to meet forecasted load growth developed by the regions in the 2023 LTRA.

Wind and Solar: 8760 hourly wind generation profiles across multiple weather years, aggregated to the TPRs. The underlying profile will be developed based on locations of specific wind and solar plants for synthetic data and actual regional output for historical data from the EIA 930 form. This will be developed using historical wind/solar generation measurements and based on historical meteorological data (see **Error! Reference source not found.**).

Behind-the-Meter Solar: A representation of distributed, behind-the-meter, solar PV will be developed based on data provided in the 2023 LTRA and EIA Form 861, which provides an estimate of small-scale solar (< 1 MW) by state. The state level solar will be disaggregated into individual county using rooftop PV estimates from Google Project Sunroof.[2] Multiple locations across each county (using zip code installation data) will be selected to develop a list of hundreds of potential PV locations and analyzed using NREL NSRDB data.

Hydro: For the purposes of this analysis, hourly correlation of hydro data to wind/solar/load is less important. Instead, hydro will be considered using historical maximum monthly generation for hydro resources in each region, including information provided by Regional Entities. This assumes that hydro generating capability is limited in each month based on outages, maintenance, and water-levels but energy limitations will not be evaluated.

Weather Dependent Outages and Fuel Supply: An estimate of *daily* generator forced outages will be developed to incorporate weather dependencies and fuel supply. The analysis will not consider individual unit outages but will develop an estimate of total capacity on outage by class of resource within each TPR. The outages will leverage NERC GADS data during recent events (2016-2023) and assumed temperature-outage rate relationships. This relationship will be used to resample historical outage rates using temperature to create a series of synthetic fleetwide outage rates intended to capture correlated risks during extreme weather and typical risks during average weather.

Planned Maintenance: An estimate of *monthly* generator planned outages, based on historical maintenance levels and nuclear refueling outages. The analysis will not consider individual unit outages but will develop an estimate of total capacity on planned outage by class of resource within each TPR based on historical NERC GADS maintenance information.

Transfer Capability: Transfer capability calculations from Part 1 of the study will be used as an input to determine prudent additions. Region-to-region and total import interface transfer capabilities will both be applied in the Part 2 model.

[2] Google Project Sunroof, https://sunroof.withgoogle.com/data-explorer/

Metrics and Screening Criteria

Hourly Energy Margin: Calculates the *hourly* energy margins during specific time periods to capture impacts of variable renewables, scheduling of storage resources, expected outage conditions, and load levels associated with specific weather conditions. This hourly data can be summarized to calculate minimum margin levels by season/month/hour of day, etc.

Hourly Energy Margin =

+ Available Wind & Solar

+ Seasonal Hydro Capacity

+ Available Thermal

– Weather Dependent Outages

– Expected Maintenance

+ Recallable Maintenance

+ Storage Net Gen

– (Load + Minimum Margin)

Notes:

- Storage will be dispatched to arbitrage hourly net load within a day (e.g., charging during off-peak hours and discharging during on-peak hours, using net load).
- To avoid or reduce instances of resource deficiency, Demand Response will be applied for a maximum of 3 hours per day with constraints on how many times per year they can be called.
- Each TPR will be evaluated without imports or exports.
- Minimum Margin is set at 3% of the load. A sensitivity will also be performed at a 6% reserve level.

Challenging period correlation: Statistics will be developed and quantified to calculate the correlation between low margin periods in one region and the relative margins in neighboring regions. This will help visualize which regions may have surplus resources to transfer during reliability events. Model output quantifying this relative difference in resource availability will be used to allocate transfer additions to where they will be most effective.

Import Dependency: A metric that quantifies the number of times, and severity, when a region may be able to meet load but is dependent on transfers from one or more neighboring regions to do so.

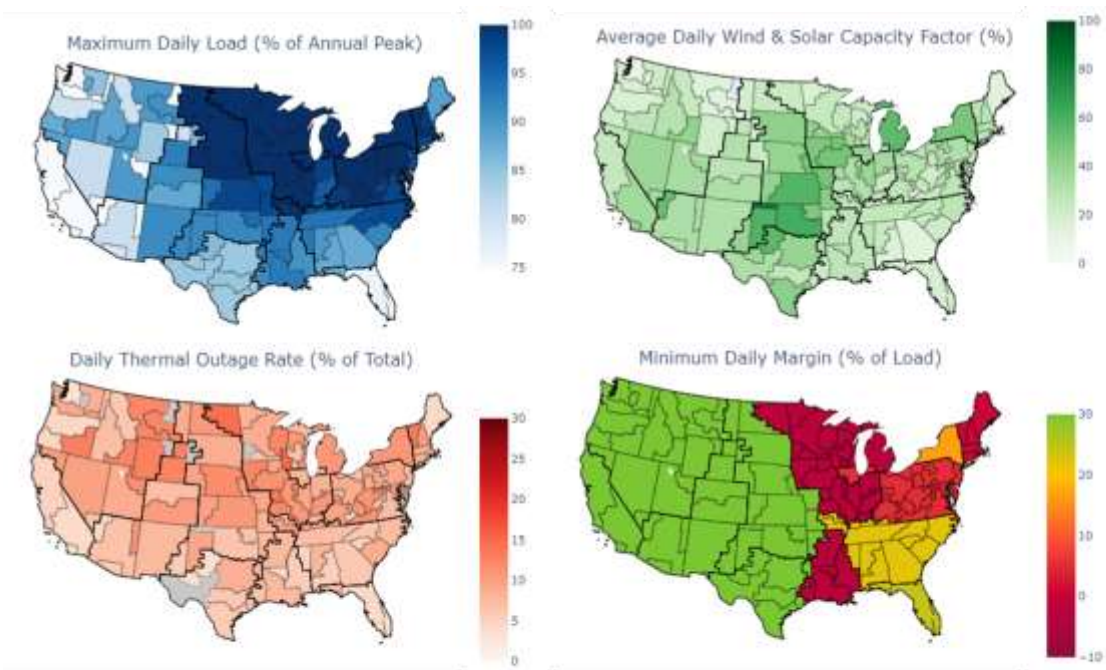
ITCS Part 2 Prudent Additions Outcomes

Part 2: The hourly energy margin evaluation will be used to identify regions where additional transfer capability would be prudent. This can be done by evaluating pairs of neighboring regions that have surplus resources available during challenging conditions. Such prudent additions may improve geographic diversity of load, wind, solar, and generator outages.

The approach to calculate prudent additions will require assessment and analysis to answer following questions:

1. Are there conditions under which a particular area will require additional transfer capability? If yes, then under what conditions (extreme cold/heat etc.) additional transfer capability will be needed?
2. How much additional transfer capability will be needed by each area under those extreme conditions? What metrics will we use to recommend additional transfer capability (unserved energy etc.)?
3. From which planning area/s would it be prudent to add transfer capability?

The extreme conditions included in the 12 years of weather data could potentially impact one area, multiple areas, and/or may move from one area to another. Simulation of each of these types of events will provide insights into the system conditions under which certain areas could potentially face energy shortfalls and which areas of the system may have surplus energy to meet the deficit. An example of this analysis is provided in Figure 2.



Source: Energy Systems Integration Group, Telos Energy

Figure 2. Geographic representation of an extreme heat case.

Study Steps

Step 1: Simulate extreme scenario and determine energy shortfall:

- Exclude any interchange between neighboring regions,

- Calculate hourly energy margin, where negative values indicate shortfalls
- Quantify energy shortfall and characterize by size (MW), frequency, duration (number of hours), and timing (times of the day).

Step 2: Determine prudent additions:

- Under the energy shortfall conditions for each area, determine which areas will have energy surpluses,
- Quantify depth of energy surpluses in neighboring regions using the hourly energy margin,
- Include existing transfer capability (from Part 1), increasing hourly energy margin in one region and decreasing margin in neighboring region due to the energy transfer,
- Increase transfer capability until energy deficit is resolved, by prioritizing neighboring regions with higher surplus available capacity,
- Apply metrics to each prudent addition and determine final recommendations for prudent additions.

Appendix A-1: Comparison of ITCS Part 1 and Part 2

Table A-1: Comparison of ITCS Part 1 and Part 2		
	Part 1: Transfer Analysis	**Part 2: Prudent Additions**
Objective	Calculate interregional transfer capability absent new transmission additions	Identify prudent additions of transfer capability for reliability
Topology	Transmission Planning Regions	Transmission Planning Regions
Case (Horizon)	1-year out	1-year out
		10-year out
Scenarios	Summer Peak (P50)	Summer Peak (P50)
	Winter Peak (P50)	Winter Peak (P50)
	n/a	Extreme Cold Snap(s)
	n/a	Extreme Heat Wave(s)
	n/a	Renewable Drought(s)
	n/a	Etc.
Portfolio (Capacity Assumptions)	MOD-32 Base Case (adjustments if necessary)	NERC LTRA, plus additional portfolios, time permitting
Load Forecast Assumptions		
Generator Dispatch Assumptions	Single Dispatch in ACPF	Full 8760 hour x N weather year analysis, Hourly energy margin based on resource availability
Load Profile Assumptions	Single Dispatch in ACPF	
Key Outputs	Transfer Capability	Seasonal and Hourly Risk
	Limiting Elements	Hourly Energy Margin
	n/a	Unserved Energy (GWh, Hours, Max MW)
	n/a	Etc.