ITCS SAMA Study Scope – Part II

March 2024

Background

Part 1 of the Interregional Transfer Capability Study (ITCS) will utilize conventional transmission planning techniques and utilize a narrow set of planning cases to quantify transfer capability. These cases include "Summer Peak," and "Winter Peak," and represent only a limited number of snapshots in time, referred to as dispatch conditions. While these represent periods of peak demand, the cases may not represent extreme conditions that may jeopardize grid reliability. In addition to quantifying existing transfer capability under these conditions, Part 2 of the ITCS, referred to as the "Energy Assessment" seeks to:

- Identify system conditions under which system could experience energy shortfalls,
- Determine prudent additions to interregional transfer capability between each pair of transmission planning region,
- Evaluate which planning area(s) are prudent to add increased transfer capability.

Purpose

This 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 – but may also be used to reassess existing transfer capability (Part 1) under challenging reliability conditions.

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 ITC,
3. Develop metrics and methods to identify which pairs of regions should be prioritized for increased interregional transfer capability,

Specifically not in-scope:

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

- Probabilistic resource adequacy analysis – 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.
- Re-dispatch of transmission planning cases to recalculate transfer capability under challenging operating conditions.

Study Tool

The Phase II study will combine large hourly datasets, custom code, and PLEXOS modeling software. The Scenarios, Assumptions, Metrics Adequacy (SAMA) team will first develop custom spreadsheet tools, augmented by python and other coding tools where necessary to quantify and visualize resource availability and load across North America. The datasets will be used in subsequent modeling tools, such as PLEXOS, by utilizing a zonal, "pipe-and-bubble" model of the North American power system, aggregating resources by fuel type, technology type, and region ("sink").

Cases and Scenarios

The ITCS will evaluate several cases, scenarios, dispatch conditions, and sensitivities. A definition of each of these terms is provided below, followed by a proposal for this analysis.

- **Case:** Represents the overall system portfolio, including installed capacity (installations and retirements), annual load level, and transmission topology.
- **Scenario:** Assumptions around a specific "event" or grid operating condition that determines load level, unit commitment, and dispatch that is created in as a dispatch example in the ACPF analysis.
- **Dispatch Condition:** A specific hourly "snapshot" in time, representing system load, generator commitment and dispatch, and used to setup the ACPF simulations.
- **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 dispatch conditions. Unlike the ITCS Part 1, which will evaluate only select scenarios and cases, the ITCS Part 2 analysis will assess a wider range of these parameters.

To quantify existing transfer capability in Part 1, the NERC ITCS will use the typical Interconnection-wide cases that were built per MOD-32 standard, which typically are developed for a current system (1-year out) and a future system (10-years out), and include two scenarios, "Summer Peak," "Winter Peak." In future, these cases will be adapted to develop alternative extreme reliability events, as shown in **Error! Reference source not found.**.

Table 1: Study Case and Scenario Matrix		
Study Cases		
Part I – Transfer Capability Analysis		
Study Scenarios	**Current System**	**10-Year Outlook**
Summer Peak	X	X
Winter Peak	X	X
Part II – Energy Assessment		
Cold Snap	X	X
Heat Wave	X	X
Renewable Drought	X	X
…other		

Case Assumptions and Portfolios

Generation portfolios will be developed for both the Current System (1-year out) and a 10-year outlook and align, to the extent reasonable, with the MOD-32 Base Case power flows used in Part 1. For Part 2 of the analysis, generation portfolios will align with the 2023 NERC Long-Term Reliability Assessment (LTRA), including similar representation for existing generators, retirements, Tier 1 and Tier 2 resource 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. Other examples include PJM-E, PJM-W, PJM-S and MISO-E, MISO-W, MISO-C, MISO-S.

Reconciliation with Part 1

It is important to note that given the difference between resource and transmission planning, some discrepancies between the Part 1 and Part 2 analysis are expected. Ideally the cases would be consistent. There are two options to handle potential discrepancies:

1. The NERC LTRA will be reflected for the energy assessment only, knowing it won't match exactly the 10-year outlook in the Part I transfer analysis.
2. The energy analysis will be based on the same resource mix in the Part I transfer analysis, but this outcome may underestimate resource portfolio and capacities.

Additional Cases

The 10-year outlook in the NERC LTRA is intended to incorporate new plant entries and exits that are known with some degree of certainty (Tier 1 and Tier 2). However, the 10-year out forecast is highly uncertain and the NERC LTRA is likely not reflective of what utilities, grid operators, and states law are currently planning to. As a result, the portfolio may understate the buildout and retirement of resources significantly. To overcome this uncertainty, additional cases may be developed for the Part 2 Energy Assessment. Examples of these additional cases may include the following:

- Utility and RTO Resource Plans, which leverage the most recent long-term IRP or system outlook developed by the regional grid operator and includes uncertain additions above and beyond named projects.
- Accelerated policy and decarbonization which could lead to an increase in renewable deployment, plant retirements, and end-use electrification,
- Slower transition, which assumes bottlenecks arise from transmission interconnection and reliability concerns that slow the pace of new resource development.

Scenario Assumptions

Once the Cases are developed, Scenario assumptions will utilize 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 options to develop this dataset:

1. Utilize historical measured data for load, wind, and solar from recent years and scale it appropriately to represent future conditions; **and,**
2. Leverage synthetic datasets using historical weather observations (temperature, wind speed, solar irradiance, etc.) and estimate load and resource availability.

Table 1 compares the benefits and limitations of the two approaches. Note that one or both options can be leveraged for this study. However, the ITCS should identify important data needs for subsequent NERC studies.

Table 1. Two options for data sources

Table 2: Two Options for Data Sources		
	Option 1 Historical Measured Data	**Option 2 Synthetic Weather Data**
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
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.**

A list of potential weather events that can be evaluated in the Part 2 analysis include the following:

- Winter Storm Elliott, 2022
- Winter Storm Uri, 2021
- Polar Vortex, 2014
- Intense Cold Wave, 2011
- Western Wide Area Heat Domes, 2020 and 2021
- Western and Midwest Heat Waves, 2023
- SPP Wind Drought, of 2023
- Additional cases based on review of historical meteorological and future climate trend data
- Additional cases may be considered, including cyber-attacks, wildfire risks, and extended planned outages, details TBD.

Study Topology

Create all inputs and assumptions on a NERC “Source/Sink” topology, which will align with the ACPF Source/Sink topology used in TARA to calculate transfer capability and should align with the NERC LTRA. Figure 1 shows the proposed Source/Sink topology that will also be used for other inputs and assumptions. All sources and sinks will be developed in a way that they can be aggregated, or “rolled up” into FERC Order 1000 regions.

- Western Interconnection Source/Sink topology determined by WECC Study Team,
- ERCOT Source/Sink to be modeled as either a single region, or separated further (i.e. West/East Texas, Panhandle, Houston),
- Canadian regions will also be considered,

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 may be more informative and comprehensive to calculate intra-regional transfer capability at a sub-regional level because availability of resource mix 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. Because at times, certain resource and transmission limitations at a sub-regional level can be masked when looked at, 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 level 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.

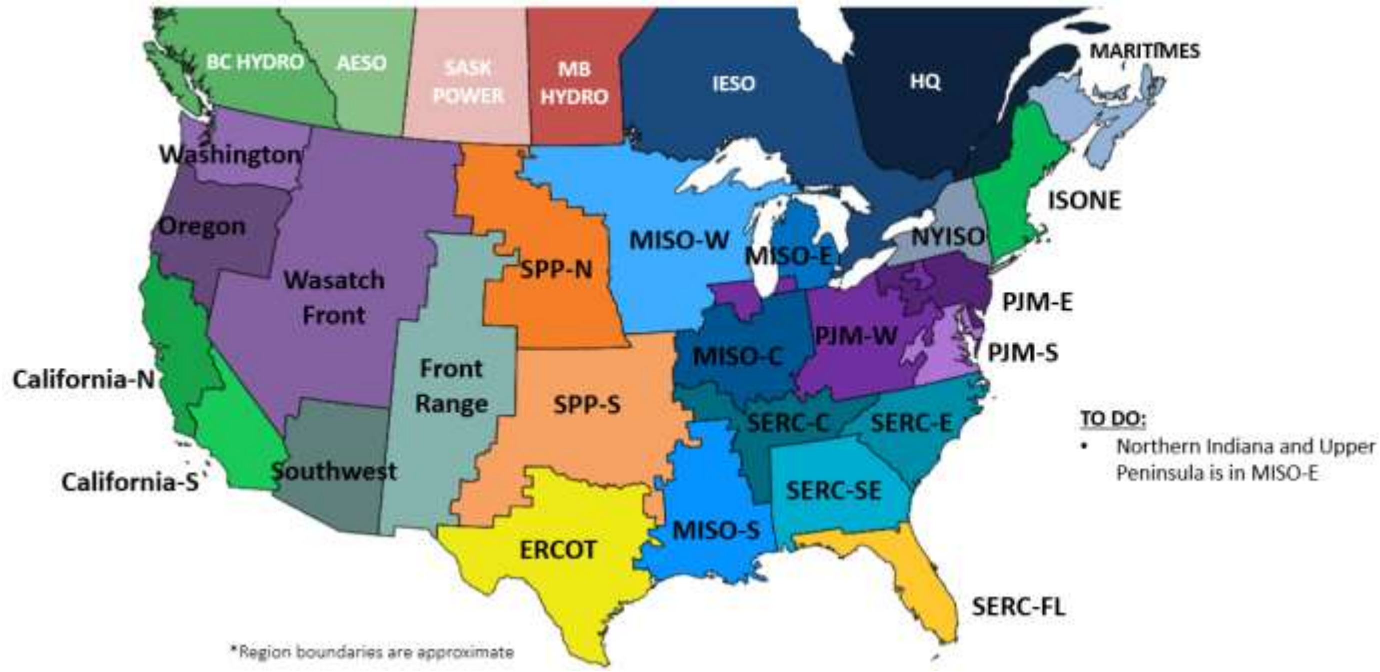


Figure 1: NERC Source Sink Topology

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 multiple weather years that change to reflect seasonality, weather impacts, day of week, etc. The ITCS will leverage either historical loads from recent event (EIA-930 and/or FERC 714) or synthetic load data from the NREL Standard Scenario dataset (see Table 1 for discussion of data options). Both sources will be scaled to meet forecasted load growth developed by the regions in their FERC 714 filings and aligned to the NERC LTRA.

Wind and Solar: 8760 hourly wind generation profiles across multiple weather years, aggregated to the NERC Source/Sink topology. The underlying profile will be developed based on locations of specific wind and solar plants, but the wind generation in the ACPF will be dispatched uniformly across the Source/Sink topology. This can be developed using either historical wind/solar generation measurements or based on historical meteorological data (see Table 1).

Behind-the-Meter Solar: A representation of distributed, behind-the-meter, solar PV will be developed based on data provided in 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.[1] 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.

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

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 monthly average, maximum, and minimum generation data for both energy (GWh) and power (MW) limits. This will allow the analysis to consider normal, drought and a high hydro condition.

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 NERC Source and Sink. The outages will be deterministic, and leverage NERC GADS daily data from 2016-2023, aggregated by fuel type and Sink. For weather years where GADS data is not available, the SAMA team will resample outage data based on historical temperature observations and outage relationships found in the GADS data.

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 NERC Source and Sink.

Transfer Capability: Transfer capability calculations from Part 1 of the study will be used as an input to determine prudent additions.

Metrics and Screening Criteria

Seasonal Reserve Margin: Similar to the NERC LTRA, the analysis will develop an estimate of planning reserve margin by Source/Sink. This will use the region's own estimates for effective load carrying capability of wind, solar, and hydro resources. This will be reported only on a seasonal, summer and winter, basis and will provide a useful comparison to LTRA and other regional planning studies.

Seasonal Reserve Margin = Available Capacity / Peak Demand
where:

- Available Capacity = Thermal Capacity (UCAP) + Hydro + Wind ELCC + Solar ELCC + Storage ELCC + Firm Net Imports
- Peak demand = Seasonal P50 Peak Demand – Demand Side Management
- Note: seasonal reserve margins can also be adapted to use P10 demand figures

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 + 6% Reserves)

Notes:

- Storage can be dispatched heuristically to arbitrage hourly net load within a day (charging during off-peak hours and discharging during on-peak hours, using net load).
- Each Source/Sink will be evaluated without imports or exports.
- Operating Reserves (spin and regulation) are set at 6% of the load, but can be adjusted as needed.

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 identify which regions may have surplus resources to transfer during a reliability event.

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 neighboring regions to do so.

ITCS Part 2 Energy Assessment Outcomes

Part 1: If time permits, the data and metrics developed in this analysis can be used to select new scenarios to reflect specific extreme reliability conditions to redispatch the MOD-32 ACPF Base Cases. Care should be taken to select the appropriate dispatch conditions and the right number of dispatch conditions to select.

Part 2: While the data and metrics will be useful in recalculating transfer capability (Phase 1), the same dataset can also be used to identify regions where additional transfer capability would be prudent. This can be done by evaluating pairs of neighboring regions that can improve geographic diversity of load, wind, solar, and generator outages.

This analysis can be evaluated across a wider range of Cases (different future renewable and retirement scenarios, for example) and across a wider range of Scenarios (many different weather conditions) to better reflect options for increasing ITC to improve reliability.

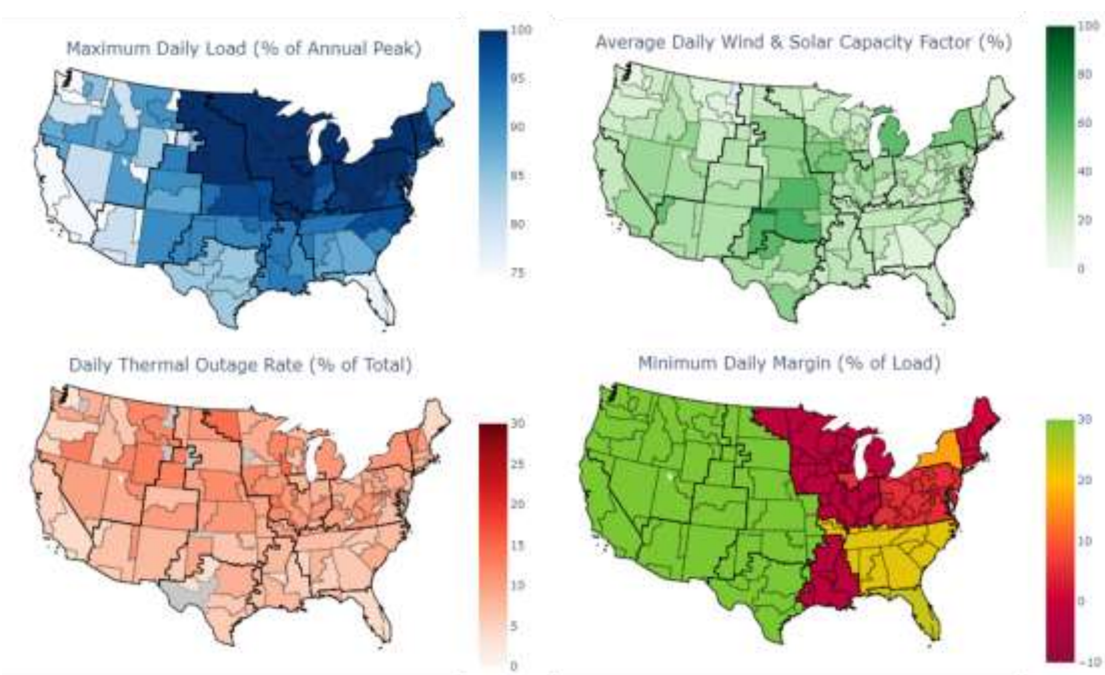
The approach to calculate prudent additions will require assessment and analysis to answer following questions:

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 would it be prudent to add additional transfer capability?

To determine system conditions that may require additional transfer capability, various scenarios will be assessed representing extreme load conditions and minimal internal generation within a particular area, as described in the previous sections. Following extreme scenarios will be assessed for Part II:

- Extreme winter
- Extreme summer
- Low renewables

The extreme scenarios could potentially impact one area, multiple areas 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 (MWs), 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,
- Utilize the hourly energy margin to quantify depth of energy surpluses in neighboring regions,
- Include transfer capability, increasing hourly energy margin in one region and decreasing margin in neighboring region due to 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.

Next Steps

1. Finalize Source/Sink Topology
2. Finalize 1-year out and 10-year out Case details on installed capacity and load forecast
3. Determine preferred data source [historical actuals and/or simulated weather]
4. Start scoping Part 3, how to meet and maintain current transfer capability and 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	Source/Sink	Source/Sink
Case (Horizon)	1-year out	1-year out
	10-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	Annual / Seasonal Planning Reserve Margin
	Limiting Elements	Hourly Energy Margin
	n/a	Unserved Energy
	n/a	Etc.