GENERATOR INTERCONNECTION MANUAL

(DISIS MANUAL)

By Generator Interconnection Department

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Version 3.0

CONTENTS

REVISION HISTORY

DATE	AUTHOR	VERSION	CHANGE DESCRIPTION
12/2019	SPP	1.0	DISIS Manual
6/2020	TSM	1.1	Model Acquisition Process & Location
11/2020	GI	1.2	Outdated Information Removed/GIS Dispatch Map Updated
4/2021	GI	1.3	ERIS Removed from NR Dispatch (DIS1701 P2 & Forward) Model Reduction DISIS Report Guide DISIS FAQs TPL-001-4 Contingency Guide Solve Parameters and Generator Outage Exception
4/2021	GI	1.3.1	Stability Dispatch Revision
8/2021	GI	1.4	Updated Study Schedule Status page link Updated REGIONAL GROUPINGS from 16 groups to 5 Regions Updated Dispatch table
12/2021	GI	1.5	Update Contact Info
4/2022	GI	1.6	Review of all sections and modifications to reflect current practice and to prepare for conversion to SPP Business Practice.
10/2022	GI	1.7	Clarified fuel-based dispatch, incorporated language from Business Practices 7250, 7300, 7350, and 7400, reorganized sections and made updates throughout per GI Manual Task Force under Transmission Working Group.
1/2023	GI	1.8	Corrected Short-Circuit Model reference section in Section 4.3.3.2. Changed from section 4.2.1 (Powerflow Model Development) to 4.3.1.1 (Stability Model Set).
7/2023	GI	1.9	Additional review of all sections and modifications to reflect current practice and to provide clarification based on questions and comments received from stakeholders.
8/2023	GI	2.0	Revise Footnote 5 (Steady-State Electrical Equivalency) to match Footnote 13 (Stability Electrical Equivalency) as approved by TWG on 8/29/2023.
1/2024	GI	2.1	Revise Steady-State Fuel-Based Dispatch Tables 1, 2, and 3 for Fuel-Based Dispatch Option 2 applicable in DISIS-2021-001 Phase 2 study and forward (RR-592).
2/2024	GI	2.2	After an appeal to the Board of Directors concerning RR-592, the implementation of Fuel-Based Dispatch Option 2 will be in DISIS-2022-001 Phase 2 study (instead of DISIS-2021-001 Phase 2) and forward.
4/2024	GI	3.0	Revise to incorporate RR590 GI Request Modifications and RR608 GI Seasonal Limited Operation

1 INTRODUCTION

This business practice is a companion to SPP's Generator Interconnection Procedures (GIP) in Attachment V of the SPP OATT. It provides additional detail and specifications describing how SPP administers the provisions in the SPP OATT related to interconnection service. To the extent that there is a conflict between the OATT and this business practice, the OATT controls.

Generator Interconnection (GI) study reports and other current information regarding study status, model requests, submissions and inquiries are available through SPP's Generator Interconnection portal on SPP.org (https://www.spp.org/engineering/generator-interconnection/).

2 DEFINITIONS

Unless noted otherwise, capitalized terms used in this document have the definitions given in the SPP Open Access Transmission Tariff. The following additional definitions are referenced in this document:

Current-Queue Request – An Interconnection Request being evaluated in the current study.

Electrically-Equivalent – A relationship between Points of Interconnection (POI) that are (1) at the same substation and nominal voltage level, (2) on the same branch[1] or on a collection of in-series two-terminal branches and associated buses and facilities[2], or (3) on the same radial branch and associated facilities.

Group - The interconnection requests are grouped into five (5) active regions based on geographical and electrical impacts; reference the geographical map in Figure 1.

Legacy – Prior to the time SPP began providing Interconnection Service under its OATT.

MW_{VER} – Maximum power output (MW) of an ITP Generator or requested capacity of a Prior-Queued Request or Current-Study Request.

MW Amount - The capacity amount (megawatt) evaluated for each request.

N-n – Transmission system with all circuits closed except *n* circuits.

ITP Generator – A generator that has been incorporated into the Integrated Transmission Planning (ITP) base reliability model set during the ITP model development process.

Point of Interconnection (POI) – The point, as set forth in Appendix A to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, where the Interconnection Facilities connect to the Transmission System. For purposes of generator interconnection studies detailed in this GI Manual, a POI is specific to a substation and voltage level.

Prior-Queued Request – An Interconnection Request that has neither been withdrawn nor terminated, that has a higher queue priority (was entered in an earlier DISIS Queue Cluster Window) than Current-Queue Requests and is not an ITP Generator.

System-Intact – N-0, Transmission system with all circuits intact

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[1] Line or transformer between two buses

[2] Where this case crosses group boundaries then the Current-Queue request will be evaluated in the closest group by impedance.

SCR_{POI} – Short-circuit ratio at the Point of Interconnection (POI)

$SCMVA_{POI}$ – Short-circuit MVA at the POI

Transfer Distribution Factor (TDF) – The impact of an interchange transaction or power injection at a bus on a given flowgate; the measure of responsiveness or change in electrical loading on system facilities due to a change in electric power transfer from one area to another expressed in as a percentage (up to 100%) of the change in power transfer.

Upgrade ID - The identification number that SPP utilizes for each upgrade.

3 ORGANIZATIONAL GROUP SUPPORT

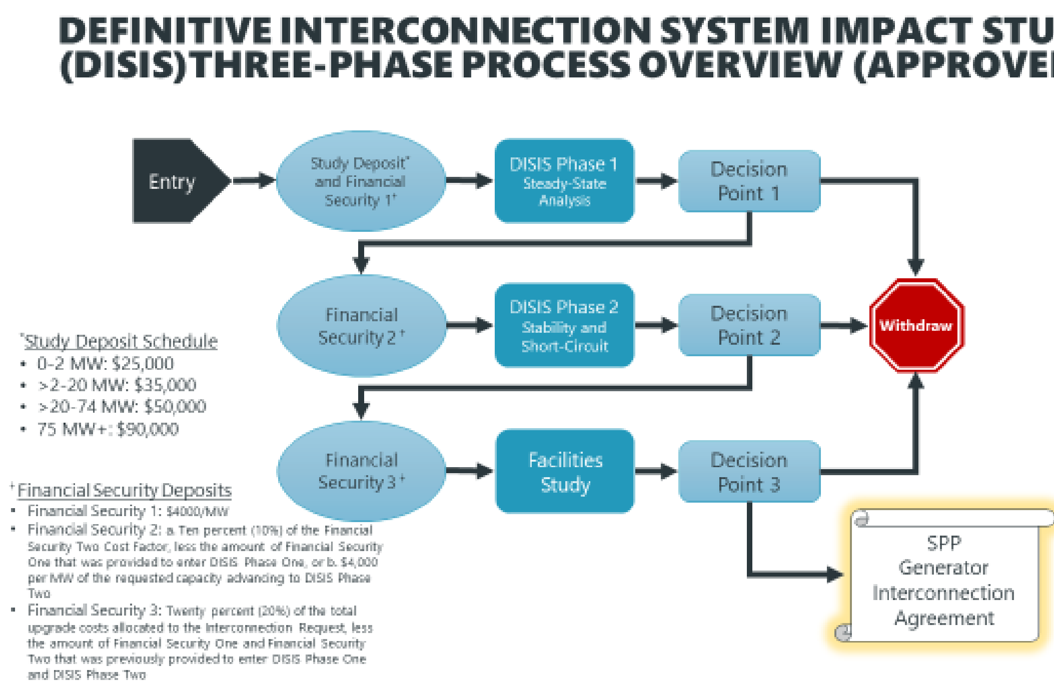
The Generation Interconnection Advisory Group (GIAG) shares information and gathers feedback related to SPP's GI studies. The GIAG relies on the collective knowledge of interested GI customers and stakeholders to assist in developing recommendations to improve SPP's GI services.

The Transmission Working Group (TWG) develops and oversees regional and interregional transmission planning processes, including generator interconnection and long-term transmission service study processes. The TWG reviews proposed transmission interconnections and coordinates transmission planning activities to develop SPP's Integrated Transmission Plan and Transmission Expansion Plan. The TWG is primarily responsible to approve GI Business Practices via SPP's Revision Request process, especially as it relates to system reliability. SPP's Regional Tariff Working Group (RTWG) is secondarily responsible to approve GI Business Practices via SPP's Revision Request process.

4 DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDIES

Definitive Interconnection System Impact Studies (DISIS) identify the steady-state violations, transient instabilities and short-circuit impacts associated with connecting generation to the transmission system. The DISIS identifies required Transmission Owner (TO) Interconnection Facilities, Network Upgrades and other Direct Assignment Facilities needed to connect at each specific Point of Interconnection (POI.)

DISIS Three-Phase Diagram



DISIS Phase 1 consists of steady-state analysis and short-circuit ratio calculation.

DISIS Phase 2 consists of steady-state analysis, stability dynamic analysis, short-circuit analysis, and short-circuit ratio and critical clearing time (SCRCCT) screening.

After each phase of study, a final report is posted with requests and upgrades. The following day after final posting, a decision point window opens for 15-business days for requests to proceed or withdrawal.

The three-phase process incentivizes withdrawals as soon as possible in the process in order to avoid multiple restudies. Additionally, the backlog mitigation plan accelerates the study process.

4.1 DISIS METHODOLOGY

Steady-state, transient stability and short-circuit analyses are conducted to study the impacts of the Interconnection Requests submitted in each Queue Cluster Window.

Interconnection Requests may be studied for one or both types of interconnection service: Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS). Note that all NRIS requests will also be studied for ERIS throughout each phase of the study process. Transmission constraints are identified based on all of the clustered generation interconnection requests being dispatched at the same time. Neither NRIS nor ERIS guarantees transmission service or deliverability pursuant to Part II or Part III of the SPP OATT. Transmission service must be requested and studied through the same process as any other Designated Resource wanting to deliver energy to a specified point (Point-to-Point Transmission Service) or to a specified Network Load (Network Integrated Transmission Service). Base Plan funding determinations for Base Plan Upgrades are subject to limits stated in Attachments Z2 and J of the SPP OATT. Upgrades required to attain either NRIS or ERIS are not eligible for Base Plan funding.

Once interconnection is complete, there is no difference between SPP Operations' treatment of NRIS and ERIS generating facilities.

4.1.1 ERIS Summary

- Energy Resource Interconnection Service allows Interconnection Customers (ICs) to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis.
- In all ERIS scenarios, dispatch uses the entire SPP footprint as a sink based on the load ratio share methodology.
- Transmission Distribution Factor (TDF) is calculated for each generation interconnection request individually by sinking to the same generators used as a sink when dispatching the ERIS cases.
- All NRIS requests are included in ERIS analysis and are evaluated as ERIS requests as ERIS service is a required level of service in order to obtain NRIS service.

4.1.2 NRIS Summary

- Transmission Provider must conduct the necessary studies and the Transmission Owner construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as Network Resources. Network Resource Interconnection Service allows Interconnection Customer's Generating Facility to be designated as a Network Resource (NR), up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

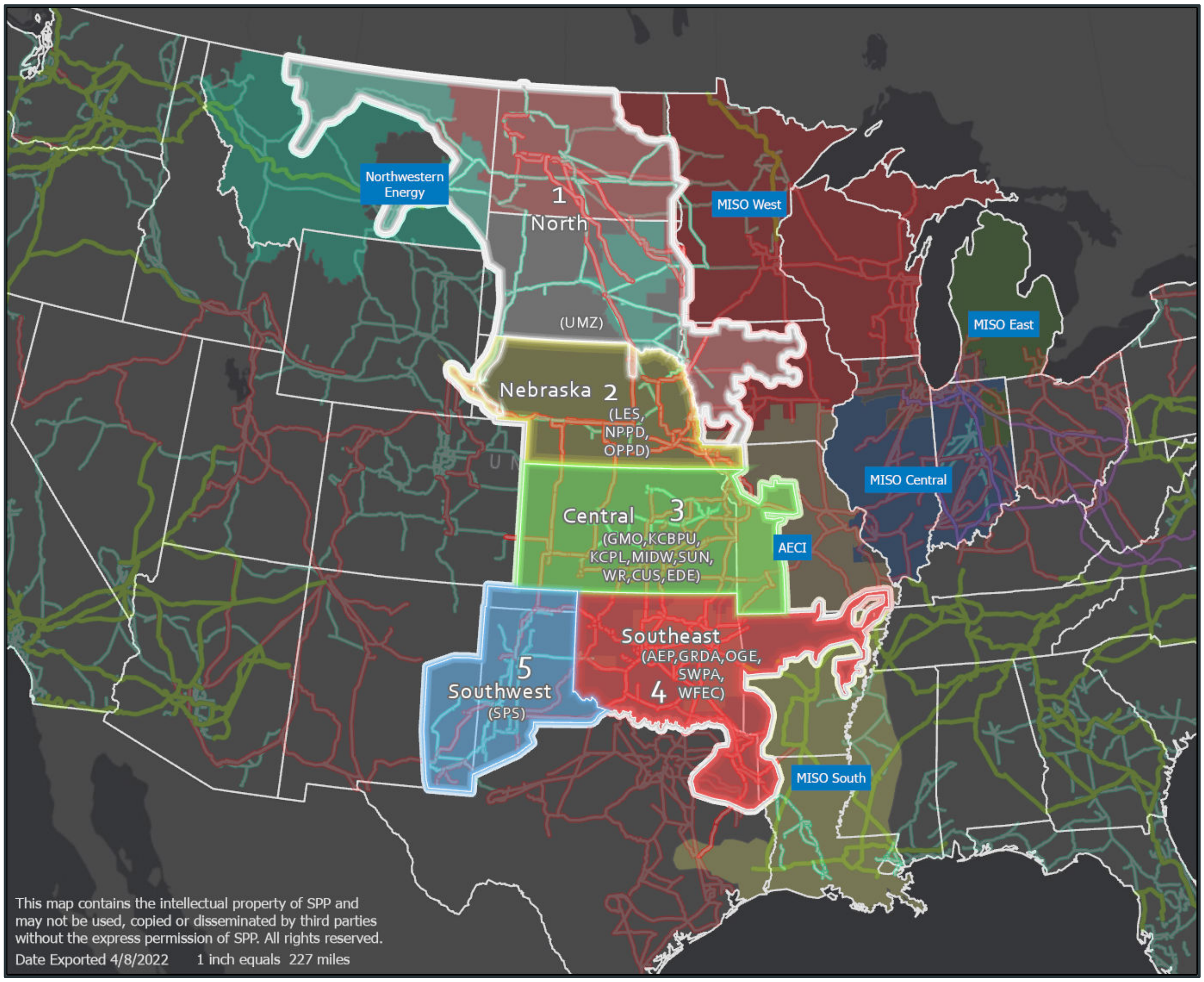
- ERIS requests are not included in NRIS dispatch unless they have approved transmission service recognized in the ITP dispatch (this change was approved by TWG 2022).
- In the NR Summer & Winter scenarios:
  - Dispatch is spread to the entire SPP footprint based on the load ratio share.
  - TDF is calculated for each generation interconnection request individually by sinking the resource to the interconnection control area (interconnection control area/Transmission Owner)
- In the NR Light scenarios:
  - Dispatch is spread to the group (01NR, 02NR, 03NR, 04NR or 05NR) in which the request is located based on the load ratio share in that group.
  - TDF is calculated for each generation interconnection request individually by sinking the resource to the interconnection control area (interconnection control area/Transmission Owner)
- Note requests may elect to convert from NRIS to ERIS during Decision Point 1 (DP1), which is contingent upon a modification election. After DP1, NRIS service election cannot be converted to ERIS.

DISIS studies are performed using a three-phase study approach. Studies are divided into phases to provide more transparency on the status of requests and to reduce the overall time for a request to go through the study process and acquire a Generator Interconnection Agreement.

4.1.3 Sub-Regional Groups

The Non-Legacy ITP Generators, Prior-Queued requests and Current-Study Requests are aggregated or clustered into sub-regional groups based on electrical impacts as generally shown in Figure 1. Generally, POIs are used as the reference point for determining location. Each request is assigned to only one group. For interconnection requests connecting between sub-regional groups, SPP will define the group by factors including, but not limited to electrical impacts, historical POI, and consistency with prior electrical impacts. Dependent on the type of service request (e.g. ERIS vs NRIS, Conventional vs Renewable), the DISIS studies will evaluate the request using a generation dispatch process involving either the entire SPP region or these sub-regional groupings or both the SPP region and the sub-regional groupings. When using the sub-regional groups, each sub-regional group’s clustered Current-Study Requests are dispatched and evaluated independent from other sub-regional groups in determining potential constraints. Constraint mitigation is coordinated between the sub-regional groups for any potential commonly identified constraints amongst the groups.

Figure 1: Approximate Location of Current Regional Cluster Groups



4.1.4 Interconnection Request Modifications

Pursuant to Attachment V of the SPP Tariff, during the course of the Interconnection Studies, customers have opportunities to make changes to their Interconnection Request(s). SPP categorizes proposed changes to an Interconnection Request into three change types: POI changes, Decision Point changes, and post-GIA changes.

Any modification to information contained in an Interconnection Request or an associated GIA, including modifications to Interconnection Facilities, should be reported to SPP to determine whether the change is permitted per the SPP tariff and this business practice and if the customer's GIA should be amended. If the change is subject to the Modification Request Impact Study, it will not be permitted without study.

4.1.4.1 POI CHANGES

After the DISIS Review Period, IC- or TO-requested POI substation and/or voltage changes are not acceptable pursuant to SPP tariff Attachment V section 4.4. For POIs that are a tap along an existing line, movement of the tap along that line meeting the following criteria is not considered a POI substation change:

- The new POI location is Electrically Equivalent with the original POI, and
- The new POI location is less than either 3 circuit miles or 10% of the circuit length (whichever is greater) from the original POI[3][4], and
- The POI maintains the same direct connections to other buses.

Pursuant to Attachment V, Section 8.2, if DISIS yields unexpected results (i.e. the interconnecting TO deems a POI technically infeasible or the POI does not meet the TO's interconnection requirements), SPP may identify an alternate POI, which may include movement of a POI tap along an existing line. SPP will consider any feedback provided prior to the start of the Interconnection Facilities Study by the interconnecting TO and Interconnection Customer in the identification of the alternate POI. If SPP identifies an alternate POI, the Interconnection Customer shall update the application to the alternate POI within the SPP-indicated timeframe (e.g. DISIS model freeze date, Phase 2 commencement) or the Interconnection Request will be deemed withdrawn pursuant to Attachment V Section 3.7.

4.1.4.2 DECISION POINT CHANGES

Customer-requested changes explicitly permitted during DP1 (see Attachment V, Section 4.4.1) will be applied starting in DISIS Phase 2 and do not require a Modification Request Impact Study.

Customer-requested changes explicitly permitted during DP2 (see Attachment V, Section 4.4.1) will be applied in any DISIS restudies, Facilities Studies, and the GIA; these changes do not require a Modification Request Impact Study.

4.1.4.3 POST-GIA CHANGES

Once the Interconnection Request's GIA is effective, the Generating Facility Replacement Evaluation and/or Modification Request Impact Study sections of this manual should be referenced.

[3] Circuit is considered a transmission line between two buses

[4] "Original POI" is that referenced in the application originally-submitted for the Interconnection Request.

4.2 STEADY-STATE ANALYSIS

The DISIS steady-state analysis involves development of powerflow models, identification of non-convergent conditions, voltage constraints, thermal constraints and cost allocation. The process generally uses the same procedures used for the ITP base reliability analysis including a common model set and contingency set, with exceptions as described in the following sections.

Steady-State analysis is performed for DISIS Phase 1 and Phase 2 and as applicable for any subsequent restudy.

4.2.1 Model Development

The ITP base reliability powerflow models serve as the starting point for all interconnection studies requiring steady state powerflow analysis. Reference [ITP Manual location](#).

ITP Model Development Set Excerpt (Base Reliability only, DISIS does not use Year 10)

Description	Year 2	Year 5	Year 10	Total
Base Reliability	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	9

The DISIS steady-state analysis uses the following years and seasons from the ITP model set:

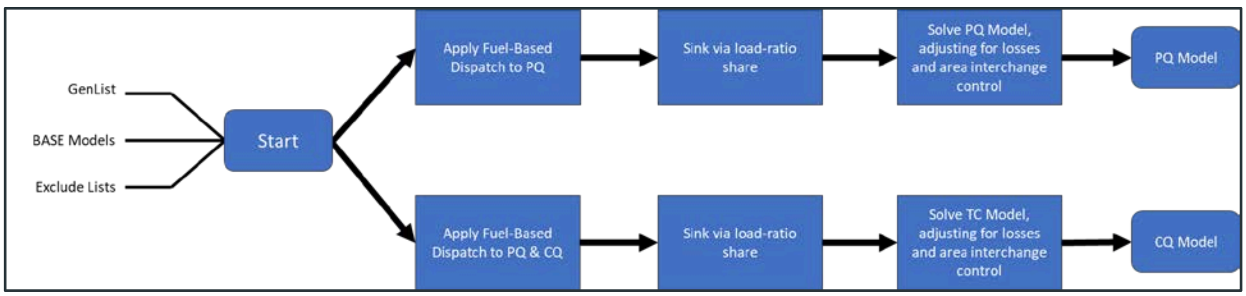
- Year 2
  - Summer Peak
- Year 5
  - Light Load
  - Summer Peak
  - Winter Peak

The ITP powerflow models are modified as follows to create a **base** model set from which the DISIS study models can be created. Updates are made to reflect changes that have occurred subsequent to the publishing of the ITP models:

- Model corrections expected to have an impact on the DISIS study results;
- Newly confirmed long-term transmission service reservations, including delivery point additions (Attachment AQ), and associated network upgrades;
- Network upgrades approved pursuant to Attachment O processes such as ITP reliability, economic, Public Policy, Sponsored Upgrades, Delivery Point Addition, high priority, etc.;
- Generators, both internal and external to SPP, that have been studied in the interconnection process but are not modeled in the ITP cases (Prior-Queued Requests), including associated network upgrades; and
- Generators associated with Current-Queue Requests.

Neither Prior-Queued Requests nor Current-Queue Requests are dispatched when developing the BASE models. ITP Generator dispatch in the BASE model may be modified in accordance with ITP Manual and ITP model build procedures to reflect new transmission service reservations, load additions and error corrections. ITP upgrades that are added to the model will be included in the seasonal cases in which they are expected to be in-service based on projected in-service dates. Each Generating Facility is represented in the powerflow models as an equivalent generator dispatched at the applicable percentage of the requested service amount with rated power factor capability. The facility modeling includes representation of equivalent generator step-up (GSU) and main power transformer(s) with impedance data provided in the interconnection request application. Collector system(s) and transmission lead line(s) shorter than 20 miles are represented as zero-impedance branches. Longer lead lines are explicitly represented.

BASE Models to Prior-Queued Models and Current-Queued Models Diagram



SPP will post BASE Models, PQ Models and CQ Models[5] and open an IC/TO comment period. ICs and TOs are requested to review only their CQ requests and specific location topology. Detailed example from above ITP Base Reliability:

DESCRIPTION	YEAR 2	YEAR 5	TOTAL
BASE	- Summer	- Summer - Winter - Light Load	**4**

[5] Maximum Count: 4 BASE + 31 PQ + 31 CQ = 66 models

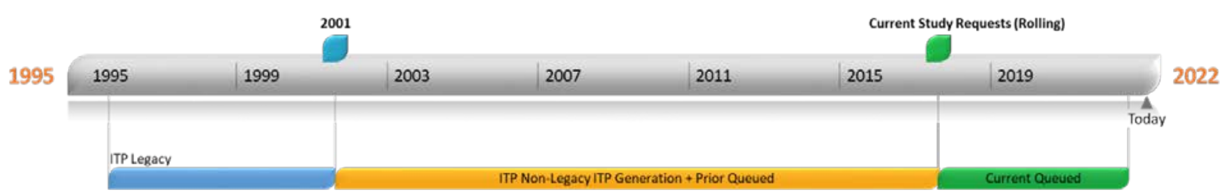
SERVICE TYPE	DISPATCH SCENARIO	YEAR 2	YEAR 5	PQ MODELS	CQ MODELS	TOTAL
ERIS	HVER	- Summer, 5 groups	- Summer, 5 groups - Winter, 5 groups - Light Load, 5 groups	20	20	40
	LVER	- Summer, SPP Region	- Summer, SPP Region - Winter, SPP Region	3	3	6
NRIS	NR	- Summer, SPP Region	- Summer, SPP Region - Winter, SPP Region - Light Load, 5 groups	8	8	16
TOTAL				**31**	**31**	**62**

4.2.1.1 GENERATOR DISPATCH

The BASE model is modified to create the **Prior-Queued model** (PQ model) set by dispatching Prior-Queued Requests according to the dispatch description in the following sections.

The base model is modified to create the **Current-Queued model** (CQ model) set by dispatching both Prior-Queued Requests and Current-Queue Requests according to the dispatch description in the following sections.

ITP Legacy and Non-Legacy Generation + Prior-Queued, and Current-Queued Differences Diagram



Legacy ITP generation was online prior to GI queue and represents generation prior to 2001. Non-Legacy ITP generation have been studied by a GI process and have reached commercial operation. These units are in the ITP base reliability models. Prior-Queued (PQ) generation has been studied by GI but has not yet reached commercial operation and is not represented in ITP base reliability models. Current-Queue (CQ) requests are active in the current study being performed. DISIS will treat these types differently according to the dispatch table below.

To simulate and analyze the variety of generation and service types included in a DISIS cluster, three dispatch scenarios are developed for both the prior-queued and current-queued case model sets.

- High-Variable Energy Resource (HVER) cases reflect scenarios in which Variable Energy Resources[6] are generating at high levels and conventional resources are at relatively low levels. HVER scenarios are developed for summer peak, winter peak, and light load seasons and are used to evaluate both ERIS-only and NRIS requests.
- Low-Variable Energy Resource (LVER) cases reflect scenarios in which Variable Energy Resources are generating at low levels and conventional resources are at relatively high levels. LVER scenarios are developed for summer and winter peak seasons only and are used to evaluate both ERIS-only and NRIS requests.
- Network Resource (NR) cases reflect scenarios in which NRIS generator output is maximized and ERIS-only generator output is minimized. NR scenarios are developed for summer peak, winter peak, and light load seasons and are used to evaluate only NRIS requests.

Cases reflective of the HVER, LVER, and NR scenarios are developed when resources in those categories are in the current DISIS. For example, if the current DISIS only includes HVER and NR requests, cases with LVER scenarios are not developed, but HVER and NR scenarios are developed.

Note that Area Interchanges are adjusted to account for transactions inferred by the Fuel Based Dispatch and sinking methodologies as described in the following sections. Regional net interchanges are held constant, however.

4.2.1.1.1 SOURCE GENERATION

The percentages in Table 1, Table 2, and Table 3 define the dispatch levels applied to Prior-Queued Requests and Current-Queue Requests in the Prior Queued and Current-Queued models with the exception noted below. The percentages in the tables are applied to the requested interconnection service amount, not to the nameplate rating.

Both ERIS-only and NRIS requests are dispatched in the HVER and LVER scenarios. NRIS requests are evaluated as ERIS requests in the HVER and LVER Scenarios. Only NRIS requests or Non-Legacy ITP ERIS generators with transmission service reservations are dispatched in the NR scenarios. Where a single Interconnection Request consists of multiple components of different fuel types, commonly known as a hybrid request, each component is dispatched individually according to its fuel type. If the resulting dispatch exceeds the requested capacity for the

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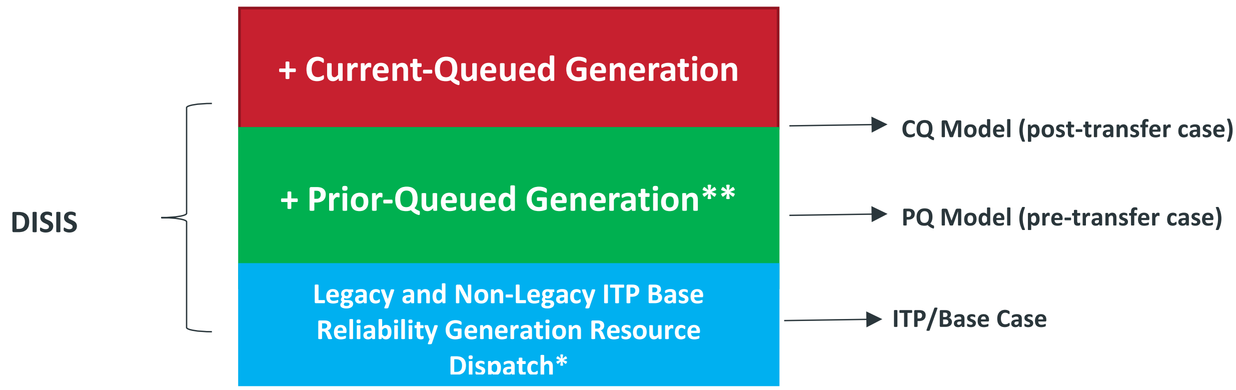
[6] See OATT Attachment AE, Section 1.1: Variable Energy Resource - A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the Facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Interconnection Request, the dispatch will be scaled down on a pro-rata basis (of calculated values) to honor requested capacity.

The dispatch levels in Table 1, Table 2, and Table 3 have been approved by the Transmission Working Group (TWG).[7] The TWG periodically reviews these dispatch levels and can recommend and approve changes as needed according to the Revision Request process.

DISIS Model Diagram (from bottom up)



*See ITP Manual Section 2.1 BASE RELIABILITY MODEL OVERVIEW describes the generation inclusion and dispatch

**Non-Legacy ITP Generator with POIs Electrically Equivalent to Current-Queued Request

- Prior-Queued: requests that are *queued* higher than the current study but not included in ITP Base Reliability Model Generation Resources
- Current-Queued generation: requests that are currently under evaluation

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[7] See minutes of the February 28-March 1, 2022 TWG meeting

Table 1: Fuel-Based Dispatch (FBD) Table for HVER Steady-State

Fuel Type	In-Group									Out-Group								
	Summer Peak			Winter Peak			Light Load			Summer Peak			Winter Peak			Light Load		
	L/NL*	PQ	CQ	L/NL*	PQ	CQ	L/NL*	PQ	CQ	L/NL	PQ	CQ	L/NL	PQ	CQ	L/NL	PQ	CQ
HVER Scenario																		
Combined Cycle	NC	0%	0%	NC	0%	0%	NC	0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%
Combustion Turbine	NC	0%	0%	NC	0%	0%	NC	0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%
Diesel Engine	NC	0%	0%	NC	0%	0%	NC	0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%
Hydro	NC	50%	50%	NC	50%	50%	NC	50%	100%	NC	NC / 0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%
Nuclear	NC	100%	100%	NC	100%	100%	NC	100%	100%	NC	NC / 0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%
Storage	NC (Summer Peak AVG)	0%	100%	NC (Winter Peak AVG)	0%	100%	NC	0%	0%	NC (Summer Peak AVG)	NC / 0%	0%	NC (Winter Peak AVG)	NC / 0%	0%	NC	NC / 0%	0%
Coal	NC	0%	0%	NC	0%	0%	NC	0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%
Oil	NC	0%	0%	NC	0%	0%	NC	0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%
Waste Heat	NC	0%	0%	NC	0%	0%	NC	0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%	NC	NC / 0%	0%
Wind	NC (Summer Peak AVG)	40%	100%	NC (Winter Peak AVG)	45%	100%	100% LTFTS	75%	100%	NC (Summer Peak AVG)	NC / 0%	20%	NC (Winter Peak AVG)	NC / 0%	20%	100% LTFTS	NC / 0%	60%
Solar	NC (Summer Peak AVG)	40%	100%	NC (Winter Peak AVG)	10%	100%	0%	0%	0%	NC (Summer Peak AVG)	NC / 0%	40%	NC (Winter Peak AVG)	NC / 0%	10%	0%	NC / 0%	0%
Hybrid	See Hybrid Example																	

L = ITP Legacy Request (pre-dates SPP GI Queue)
NL = ITP Non-Legacy Request (have been studied in a GI process and are in the ITP models)
PQ = Prior-Queued Requests under active study
CQ = Current-Queue Requests under active study
NC = No Change in dispatch from BASE model (see notes below)
LTFTS = Long-Term Firm Transmission Service
Percentages are based on the requested interconnection service amount in megawatts.
NOTE: Per the base sinking methodology, L or NL requests are included in the sink definition
NOTE: PQ and NL generators which are co-located with a CQ request (Electrically Equivalent) are dispatched at the same percentage of a CQ request (in-group only)

* In-Group ITP Non-Legacy generators with Non-Firm Transmission Service (not dispatched in the ITP BASE model) will be dispatched at PQ percentages and not included in sink definition.

NOTE: Non-Legacy ITP generators are firm and non-firm Variable Energy Resources (e.g., Solar and Wind) not dispatched in the ITP Base model consistent with the ITP Manual.

NOTE: Non-Variable Energy Resources are assumed to have been considered for dispatch as needed in the ITP Base model consistent with the ITP Manual; these resources will not follow the Fuel-Based Dispatch Table for Steady-State.

Table 2: Fuel-Based Dispatch (FBD) Table for LVER Steady-State

Fuel Type	In-Group									Out-Group								
	Summer Peak			Winter Peak			Light Load			Summer Peak			Winter Peak			Light Load		
	L/NL*	PQ	CQ	L/NL*	PQ	CQ	L/NL	PQ	CQ	L/NL	PQ	CQ	L/NL	PQ	CQ	L/NL	PQ	CQ
LVER Scenario																		
Combined Cycle	NC	100%	100%	NC	100%	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Combustion Turbine	NC	100%	100%	NC	100%	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Diesel Engine	NC	100%	100%	NC	100%	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hydro	NC	50%	50%	NC	50%	50%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Nuclear	NC	100%	100%	NC	100%	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Storage	NC (Summer Peak AVG)	100%	100%	NC (Winter Peak AVG)	100%	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Coal	NC	100%	100%	NC	100%	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Oil	NC	100%	100%	NC	100%	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Waste Heat	NC	100%	100%	NC	100%	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Wind	NC (Summer Peak AVG)	20%	20%	NC (Winter Peak AVG)	20%	20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar	NC (Summer Peak AVG)	40%	40%	NC (Winter Peak AVG)	10%	10%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hybrid	See Hybrid Example																	

L = ITP Legacy Request (pre-dates SPP GI Queue)
NL = ITP Non-Legacy Request (have been studied in a GI process and are in the ITP models)
PQ = Prior-Queued Requests under active study
CQ = Current-Queue Requests under active study
NC = No Change in dispatch from BASE model (see notes below)
N/A = Not Applicable for this scenario
LTFTS = Long-Term Firm Transmission Service
Percentages are based on the requested interconnection service amount in megawatts.
NOTE: Per the base sinking methodology, L or NL requests are included in the sink definition
NOTE: PQ and NL generators which are co-located with a CQ request (Electrically Equivalent) are dispatched at the same percentage of a CQ request (in-group only)

* In-Group ITP Non-Legacy generators with Non-Firm Transmission Service (not dispatched in the ITP BASE model) will be dispatched at PQ percentages and not included in sink definition.

NOTE: Non-Legacy ITP generators are firm and non-firm Variable Energy Resources (e.g., Solar and Wind) not dispatched in the ITP Base model consistent with the ITP Manual.
NOTE: Non-Variable Energy Resources are assumed to have been considered for dispatch as needed in the ITP Base model consistent with the ITP Manual; these resources will not follow the Fuel-Based Dispatch Table for Steady-State.

Table 3: Fuel-Based Dispatch (FBD) Table for NR Steady-State

Fuel Type	In-Group									Out-Group								
	Summer Peak			Winter Peak			Light Load			Summer Peak			Winter Peak			Light Load		
	L/NL*	PQ	CQ	L/NL*	PQ	CQ	L/NL*	PQ	CQ	L/NL	PQ	CQ	L/NL	PQ	CQ	L/NL	PQ	CQ
NR Scenario																		
Combined Cycle	NC	100%	100%	NC	100%	100%	NC	0%	0%	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC / 0%	0%
Combustion Turbine	NC	100%	100%	NC	100%	100%	NC	0%	0%	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC / 0%	0%
Diesel Engine	NC	100%	100%	NC	100%	100%	NC	0%	0%	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC / 0%	0%
Hydro	NC	50%	50%	NC	50%	50%	NC	50%	100%	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC / 0%	0%
Nuclear	NC	100%	100%	NC	100%	100%	NC	100%	100%	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC / 0%	0%
Storage	NC (Summer Peak AVG)	100%	100%	NC (Winter Peak AVG)	100%	100%	NC	0%	0%	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC / 0%	0%
Coal	NC	100%	100%	NC	100%	100%	NC	0%	0%	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC / 0%	0%
Oil	NC	100%	100%	NC	100%	100%	NC	0%	0%	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC / 0%	0%
Waste Heat	NC	100%	100%	NC	100%	100%	NC	0%	0%	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC / 0%	0%
Wind	NC (Summer Peak AVG)	20%	100%	NC (Winter Peak AVG)	20%	100%	100% LTFTS	60%	100%	N/A	N/A	N/A	N/A	N/A	N/A	100% LTFTS	NC / 0%	60%
Solar	NC (Summer Peak AVG)	40%	100%	NC (Winter Peak AVG)	10%	100%	0%	0%	0%	N/A	N/A	N/A	N/A	N/A	N/A	0%	NC / 0%	0%
Hybrid	See Hybrid Example																	

L = ITP Legacy Request (pre-dates SPP GI Queue)
NL = ITP Non-Legacy Request (have been studied in a GI process and are in the ITP models)
PQ = Prior-Queued Requests under active study
CQ = Current-Queue Requests under active study
NC = No Change in dispatch from BASE model (see notes below)
N/A = Not Applicable for this scenario
LTFTS = Long-Term Firm Transmission Service
Percentages are based on the requested interconnection service amount in megawatts.
NOTE: Per the base sinking methodology, L or NL requests are included in the sink definition
NOTE: PQ and NL generators which are co-located with a CQ request (Electrically Equivalent) are dispatched at the same percentage of a CQ request (in-group only)

* In-Group ITP Non-Legacy generators with Non-Firm Transmission Service (not dispatched in the ITP BASE model) will be dispatched at PQ percentages and not included in sink definition.

NOTE: Non-Legacy ITP generators are firm and non-firm Variable Energy Resources (e.g., Solar and Wind) not dispatched in the ITP Base model consistent with the ITP Manual.
NOTE: Non-Variable Energy Resources are assumed to have been considered for dispatch as needed in the ITP Base model consistent with the ITP Manual; these resources will not follow the Fuel-Based Dispatch Table for Steady-State.

Prior-Queued Hybrid Example (HVER Model)

Hybrid Request #	Hybrid Request Capacity	Type	Installed Capacity (MW)	Summer Peak	Winter Peak	Light Load
1	**100 MW**	Solar	50	40%*50MW= 20MW	10%*50MW= 5MW	0%*50MW= 0MW
		Wind	100	40%* 100MW= 40MW	45%* 100MW= 45MW	75%* 100MW= 75MW
		Total	**150**	**60MW**	**50MW**	**75MW**
2	**190 MW**	Storage	100	0%*100MW= 0MW	0%*100MW= 0MW	0%*100MW= 0MW
		Wind	200	40%*200MW= 80MW	45%*200MW= 90MW	75%*200MW= 150MW
		Total	**300**	**80MW**	**90MW**	**150MW**

If requested Hybrid capacity is exceeded by calculated values, dispatch will be scaled down on a pro rata basis (of calculated values) to honor requested capacity
Example assumes hybrid is in-group, but not at a current study gen's Electrically Equivalent POI

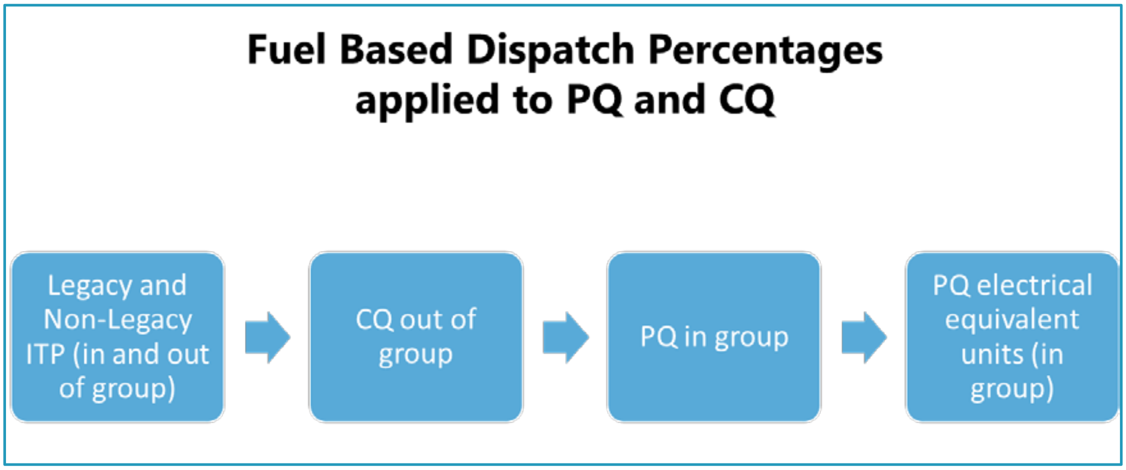
Current-Queue Hybrid Example (HVER Model)

Hybrid Request #	Hybrid Request Capacity	Type	Installed Capacity (MW)	Summer Peak	Winter Peak	Light Load
1	**100 MW**	Solar	50	100%*50MW= 50MW→33MW	100%*50MW= 50MW→33MW	0%*50MW= 0MW
		Wind	100	100%* 100MW= 100MW→67MW	100%* 100MW= 100MW→67MW	100%* 100MW= 100MW
		Total	**150**	**150MW→100MW**	**150MW→100MW**	**100 MW**
2	**190 MW**	Storage	100	100%*100MW= 100MW→63MW	100%*100MW= 100MW→63MW	0%*100MW= 0MW→0MW
		Wind	200	100%*200MW= 200MW→127MW	100%*200MW= 200MW→127MW	100%*200MW= 200MW→190MW
		Total	**300**	**300MW→190MW**	**300MW→190MW**	**200MW→190MW**

If requested Hybrid capacity is exceeded by calculated values, dispatch will be scaled down on a pro rata basis (of calculated values) to honor requested capacity
Example assumes hybrid is in-group

4.2.1.1.2 SOME REQUESTS MAY BE DISPATCHED AT THE IN-GROUP CURRENT-QUEUE REQUEST AMOUNT FOR EACH RESPECTIVE GROUP IF THEY ARE ELECTRICALLY EQUIVALENT. SINK GENERATION

In order to maintain gen-load balance within each planning region and maintain seams interchanges, generators not enforced to specific dispatch levels in the Fuel Based Dispatch (FBD) process (non-PQ and non-CQ generators) are eligible to be adjusted (sink units). Units labeled as must run as identified in the ITP Base Reliability and Economic dispatch methodologies, including but not limited to hydroelectric, cogeneration facilities, landfill gas and nuclear units, are excluded from consideration for sinking generation. The following chart represents steady-state sink order:



In the ERIS scenarios, SPP generation imbalances due to FBD are offset by reducing the dispatch of sink generators as defined above based on the load-ratio share (LRS) of the Transmission Owner powerflow modeling control areas[8].

$$Control\ Area\ LRS\ \% = \frac{Control\ Area\ Load}{SPP\ Total\ Load}$$

$$Control\ Area\ MW\ to\ sink = Control\ Area\ LRS\ \%\ x\ Total\ SPP\ MW\ Imbalance$$

Units included in the sink definition within each Control Area are scaled on a proportional basis while enforcing machine minimum limits. If insufficient generation exists in the sink for a given Control Area, the remaining imbalance assigned to that Control Area is redistributed to the remaining SPP areas.

$$New\ Control\ Area\ LRS\ \% = \frac{Control\ Area\ Load}{SPP\ Total\ Load - Deficient\ Control\ Area\ Load}$$

This process continues until the SPP imbalance is corrected or until there is no available generation left in the SPP region sink system. If an imbalance remains due to insufficient sink capacity, the process is repeated by enlarging the sink definition progressively as described below until the SPP system is balanced:

1. The Current-Queue Requests out-of-group will be reduced from the fuel-based dispatch levels in Table 1, Table 2, and Table 3 on a pro rata basis.

[8] Transmission Owner power flow modeling areas are defined in Appendix V of the Eastern Interconnection Reliability Assessment Group's Multiregional Modeling Working Group Procedural Manual (https://rfirst.org/ProgramAreas/ESP/ERAG/MMWG/)

2. Prior-Queued Requests in-group will be reduced from the fuel-based dispatch levels on a pro-rata basis excluding the fuel-based dispatch Electrically Equivalent exception cases as defined above.

3. Prior-Queued Requests in-group designated as Electrically Equivalent will be reduced from the fuel-based dispatch levels on a pro-rata basis.

If the above options are not sufficient to correct the imbalance, further reductions will be determined on a case-by-case basis and may include reducing Current-Queued requests from the fuel-based dispatch levels on a pro-rata basis, turning off ITP generators, and reducing generation external to SPP.

In the NRIS light load scenarios, SPP generation imbalances due to FBD are offset by reducing the dispatch of sink units by method of a Group LRS instead of by a regional LRS.

$$Control\ Area\ LRS\ \% = \frac{Control\ Area\ Load}{Group\ Total\ Load}$$

$$Control\ Area\ MW\ to\ sink = Control\ Area\ LRS\ \%\ x\ Total\ Group\ MW\ Imbalance$$

In the NRIS summer peak and winter peak scenarios, generation imbalances are handled by the same method used as the ERIS analysis.

For non-SPP regions (both ERIS and NRIS scenarios), a proportional, uniform scaling across all sink units in each region is used to offset the regional imbalance. If insufficient generation is available in sink system, the same process is used as defined above to enlarge the sink definition until the imbalance is corrected.

4.2.2 Contingency Analysis

After the study models are developed, SPP performs a contingency analysis on the Current-Queued model set to identify potential non-convergent conditions, voltage constraints and thermal constraints. The ITP contingency, subsystem, and monitored element files are used as the base auxiliary files. These auxiliary files are updated to include sink subsystem(s) used when calculating TDFs for each CQ request, consistent with the dispatch process sink system (ERIS). For NRIS TDF impact analysis, sink systems consist of local Control Areas. Lastly, subsystem files include a system to be used to account for generation and/or load imbalances introduced by contingencies to prevent the system swing from accounting for these imbalances.

Consistent with the ITP, contingencies evaluated for DISIS include those events listed in North American Electric Reliability Corporation (NERC) standard TPL-001-4 Table 1 that do not permit loss of non-consequential load or interruption of firm transmission service. P3 events (loss of a generator followed by a second contingency event) are not evaluated for interconnection service because the standard permits the adjustment of generation prior to the second event, which for interconnection studies would result in duplication of a P1 (single contingency) event.

The ITP contingencies may be modified as needed to reflect topology changes introduced by the addition of generating facilities and upgrades.

Network constraints are found by performing AC contingency calculation (ACCC) analysis. There may be constraints that exist in the PQ model(s) that also are identified in the CQ model(s). These constraints may be the result of different dispatches or system conditions that did not allow for these constraints to exist. As such, CQ projects are assigned to these constraints if they meet the applicable criteria.

The following solution parameters are used for both the initial development of the study models as well as the contingency analysis:

- Fixed Slope Decoupled Newton-Raphson
- Tap Adjustment – Stepping
- Switch Shunt Adjustments – Enable All
- Adjust Phase Shift
- Adjust DC Taps
- VAR Limits – Apply Immediately

For the study model build, area interchange control is enabled via tie lines and loads. For contingency analysis, the following table details the area interchange option based on the event type.

Table 4: Area Interchange Settings

EVENT TYPE	AREA INTERCHANGE CONTROL
Model Build/System Intact	Enabled (Tie Lines and Loads)
Generator	Disabled[9]
Transmission Circuit	Disabled
Transformer	Disabled
Shunt Device	Disabled
Loss of Multiple Elements (Excluding Generator)	Disabled
Loss of Multiple Elements (Including Generator)	Disabled[10]

4.2.2.1 NON-CONVERGED CONDITIONS

Identification of non-convergence is a process to ensure identified issues are not associated with tool limitations or methods, but rather are true system deficiencies. A first pass analysis is used to identify an initial list of contingencies that may result in a non-converged or blown-up state. These contingencies are further tested to attempt to reach a converged state. Examples of further tests include, but is not limited to:

- Ensuring toggling reactive devices or transformer taps are not preventing a converged state. This can be done programmatically by limiting the number of devices allowed to adjust at a given time or manually checked by locking devices.
- Testing the contingency in multiple tools/software to see if a different solution engine yields a converged state.
- Relaxing some solution parameters that may be causing numerical instability.
- Reviewing reactive devices for locked devices that may be contributing to convergence issues or prevented from offering system support.
- Reviewing Interconnection Projects for data errors or improper modeling causing solution problems.

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[9] See minutes of TWG meeting Feb. 28 – Mar. 1, 2022: SPP Reserve Group (all generation excluding Wind, Solar, and Hydro) is dispatched to make up for generation outage.

[10] SPP Reserve Group (all generation excluding Wind, Solar, and Hydro) is dispatched to make up for generation outage.

Following the iterative review of problematic contingencies, remaining non-converged contingencies are determined to be attributable to the Current-Queue. Appropriate transmission support will be identified to mitigate the constraint(s).

Upgrades required to mitigate non-converged conditions will be assigned to every Current-Queue request having a Power Transfer Distribution Factor (PTDF) impact of at least 3% on the contingent element monitored in the direction of system intact MW flow causing non-convergence.

In the case of system intact non-convergence, upgrades in the form of reactive devices are identified to allow the system to reach a converged state. Note, these upgrades are not intended to fully mitigate system deficiencies such as overloads or low voltage conditions, but only added to achieve a solved state. These upgrades may become unnecessary as other Networks Upgrades are identified and added to the system. In these cases, the system intact non-converged upgrades will be removed from the case and not assigned. When these upgrades remain as part of the upgrade package, they are assigned by identifying projects with PTDFs of at least 3% on the line with largest system intact MW flow into the bus where the upgrade was placed.

4.2.2.2 THERMAL OVERLOADS

Every element in the SPP planning models has a normal (Rate A) and emergency (Rate B) rating. Thermal overloads are identified when the flow across a monitored element exceeds either its normal rating under System-Intact conditions or its emergency rating under contingency conditions. Thermal overloads are identified using the Current-Queue (CQ) model set which incorporates a cluster generation dispatch for all CQ requests as described in section 4.2.1.1.2.

Upon identifying thermal overloads, each individual Current-Queue Request's impact on those thermal overloads is determined using a separate Transfer Distribution Factor (TDF) analysis as described below.

Upgrades required to mitigate constraints identified in the ERIS scenarios will be assigned to every Current-Queue Request meeting any of the following criteria:

- TDF impact on each overloaded facility is calculated for each CQ request using the individual generator facility as the source and sinking that resource to the same generators used as a sink when dispatching the ERIS cases.
- At least 3% TDF impact where the constraint is identified under System-Intact conditions,
- At least 20% TDF impact where the constraint is identified under contingency conditions,
- At least 5% TDF impact where the constraint is identified under contingency conditions where the sum of all Current-Queue Requests having a TDF impact on the constrained element of at least 5% equals at least 20% of the constrained element's emergency rating.

Upgrades required to mitigate constraints identified in the NR scenarios will be assigned to every NRIS Current-Queue Request meeting any of the following:

- TDF impact on each overloaded facility is calculated for each CQ request using the individual generator facility as the source and sinking that resource to the interconnection control area (interconnection control area/Transmission Owner)
- At least 3% TDF impact, where the constraint is identified under System-Intact conditions,
- At least 3% TDF impact, where the constraint is identified under contingency conditions

4.2.2.3 VOLTAGE VIOLATIONS

After all non-converged contingency and thermal overload mitigations are determined, any remaining voltage violations are checked to determine applicability to the Current-Queue. The following voltage performance guidelines are used in accordance with the Transmission Owner local area planning criteria.[11]

SPP voltage criteria[12] is applicable to all SPP facilities 69 kV and greater in the absence of more stringent criteria.

Per Unit voltages must change by at least 2% from the Prior-Queued models to the Current-Queued models to be assigned to the current cluster. For constraints meeting this criteria, requests having at least 3% PTDF on the contingent element monitored in the direction of system intact MW flow causing voltage constraints will be assigned responsibility for mitigating the voltage issue(s). For system intact voltage constraints, PTDFs of at least 3% on the line with **largest system intact MW flow** into the bus experiencing the voltage constraint is used to assign responsibility.

4.2.2.4 FIRST-TIER EXTERNAL AREAS FACILITIES 115 KV AND GREATER

Consistent with the ITP, first-tier areas will be monitored to identify potential reliability needs. SPP coordinates the contingency definitions and monitoring criteria with the external area.[13]

4.2.3 Solution Process and Methodology

When conducting constraint analysis, solutions and/or mitigations are used to resolve the identified issues. During the mitigation analysis, upgrades that have been identified are added to the models in sequential order as shown in Table 5 below. This is done as a holistic approach to use common, previously identified mitigations to aid in the mitigation of constraints that are identified later in the analysis process.

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[11] See each Transmission Owner's local area planning criteria posted on SPP OASIS http://www.oasis.oati.com/ (requires certificate to access)

[12] See SPP Planning Criteria Section 5.4

[13] See SPP ITP Manual Section 4.2.4

Table 5: Solution Set Implementation

Service Type	Scenario	Description
ERIS	S0	No upgrades (except for temporary reactive elements as described below)
	S1	ERIS upgrades mitigating non-converged contingencies
	S2	ERIS upgrades mitigating non-converged contingencies and thermal violations
	S3	ERIS upgrades mitigating non-converged contingencies, thermal and voltage violations
NRIS	S0	All ERIS upgrades (addition of temporary reactive elements as described below)
	S1	All ERIS upgrades + NRIS upgrades mitigating non-converged contingencies
	S2	All ERIS upgrades + NRIS upgrades mitigating non-converged contingencies and thermal violations
	S3	All ERIS upgrades + NRIS upgrades mitigating non-converged contingencies, thermal and voltage violations

For S0, the powerflow cases may be in a severely stressed condition and require system support to be able to solve and achieve a stable state. To that end, temporary reactive elements may be added to the model to reach this state. These elements are only added in the event that existing reactive equipment is insufficient. A list of these temporary reactive devices is provided with the study models.

For the S1 portion of the mitigation process, solutions are used to solve non-converged constraints and, if applicable, remove temporary reactive elements. Temporary reactive devices may also be deemed appropriate solutions to non-convergence and be used as mitigations and will be assigned and cost allocated accordingly.

During the process of constraint analysis, multiple alternate solutions are determined through the process, but only one is chosen as the final solution. The final solution set is first and foremost reliable. All constraints both System-Intact and N-n are to be resolved for system reliability to be considered achieved. Next, the least-cost solution is chosen. Minimization of cost is considered not on an individual request basis, but for the cluster as a whole. Solutions are subject to change based on feedback from the respective Transmission Owner (limiting equipment ratings, feasibility, etc.). Lastly, solutions may mitigate system issues spanning multiple groups within SPP. All projects assigned to constraints mitigated by these solutions will be assigned cost responsibility.

During the DISIS, S0 and S3 are represented in model sets (both for ERIS and NRIS) and are posted for IC and TO review.

4.3 STABILITY AND SHORT-CIRCUIT STUDY

4.3.1 Modeling

4.3.1.1 STABILITY MODEL SET

The SPP Model Development Advisory Group (MDAG) dynamic stability models serve as the starting point for all studies requiring dynamic analysis. Reference SPP Model Development Procedure Manual location.

The DISIS stability analysis uses the following years and seasons from the MDAG/TPL model set:

- Year 5 Summer Peak.
- Year 5 Winter Peak.

SPP will post BASE, PQ, and CQ models along with the Phase 2 draft report.

DESCRIPTION	YEAR 5	TOTAL
BASE	Summer, Winter	2
PQ, CQ	Summer, Winter	4
TOTAL		**6**

4.3.1.2 SHORT CIRCUIT MODEL SET

The Year 5 Summer Peak Stability model is used for short circuit analysis.

4.3.1.3 GENERATING FACILITY AND INTERCONNECTION FACILITIES

Each Generating Facility is represented in the dynamic stability models as an equivalent generator dispatched at the applicable percentage of the requested service amount. The facility modeling includes representation of equivalent GSU and main power transformer(s), with impedance data and power factor capability provided in the interconnection request. Equivalent collector system(s) and transmission lead line(s) impedances are also explicitly modeled for dynamic stability analysis. Dynamic stability models provided by interconnection customers are assumed to properly represent their facilities. Model tuning for interconnection facilities is not performed during the GI process.

4.3.1.4 STABILITY MODEL DISPATCH

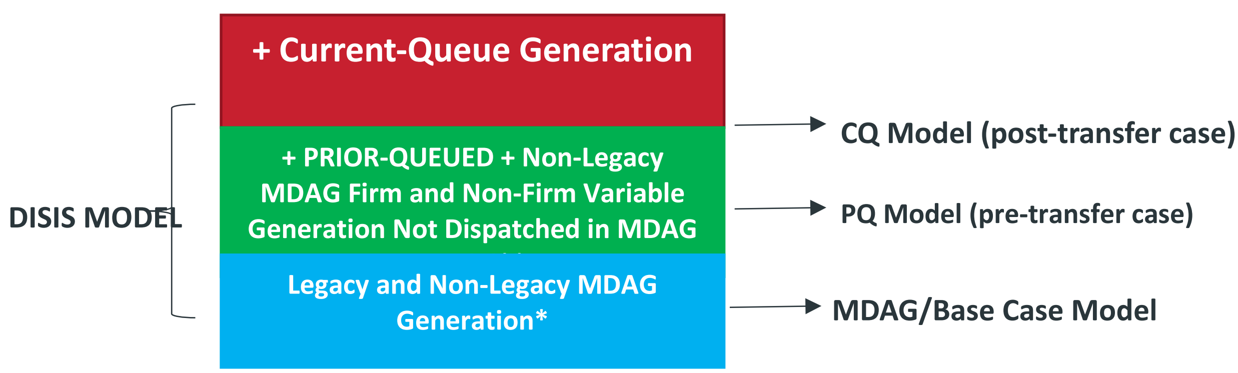
4.3.1.4.1 SOURCE GENERATION

The percentages in Table 6 define the dispatch levels applied to non-Legacy MDAG generators[14], Prior-Queued Requests and Current-Queue Requests in the Prior-Queued and Current-Queued models with the exception noted below. The dispatch levels in the table are applied to the requested interconnection service amount, not to the nameplate rating.

Generators are dispatched the same regardless of ERIS or NRIS request type. Where a single Interconnection Request consists of multiple components of different fuel types, commonly known as a hybrid request, each component is dispatched individually according to its fuel type. If the resulting dispatch exceeds the requested capacity for the Interconnection Request, the dispatch will be scaled down on a pro-rata basis (of calculated values) to honor requested capacity.

The dispatch levels in Table 6 have been approved by the TWG. The TWG periodically reviews these dispatch levels and can recommend and approve changes as needed according to the Revision Request process.

DISIS Model Diagram (from bottom up)



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[14] Non-Legacy MDAG generators are firm and non-firm Variable Energy Resources (e.g., Solar and Wind) not dispatched in the MDAG model consistent with the SPP Model Development Procedure Manual. Non-Variable Energy Resources are assumed to have been considered for dispatch as needed in the MDAG model consistent with the SPP Model Development Procedure Manual; these resources will follow the Fuel Based Dispatch Table for Stability on a limited case-by-case basis.

*See MDAG Modeling Process for Generator Parameters, Modeling of Conventional Generation PGEN, Modeling of Battery Resources PGEN, Modeling of Wind/Solar Renewable Resources PGEN sections describe the generation inclusion and dispatch

**Non-Legacy MDAG Generator with POIs Electrically Equivalent to Current-Queued Request

- Prior-Queued: requests that are *queued* higher than the current study not included in MDAG Base Model Generation Resources

∗ Current-Queue: requests that are currently under evaluation

Table 6: Fuel Based Dispatch Table for Stability

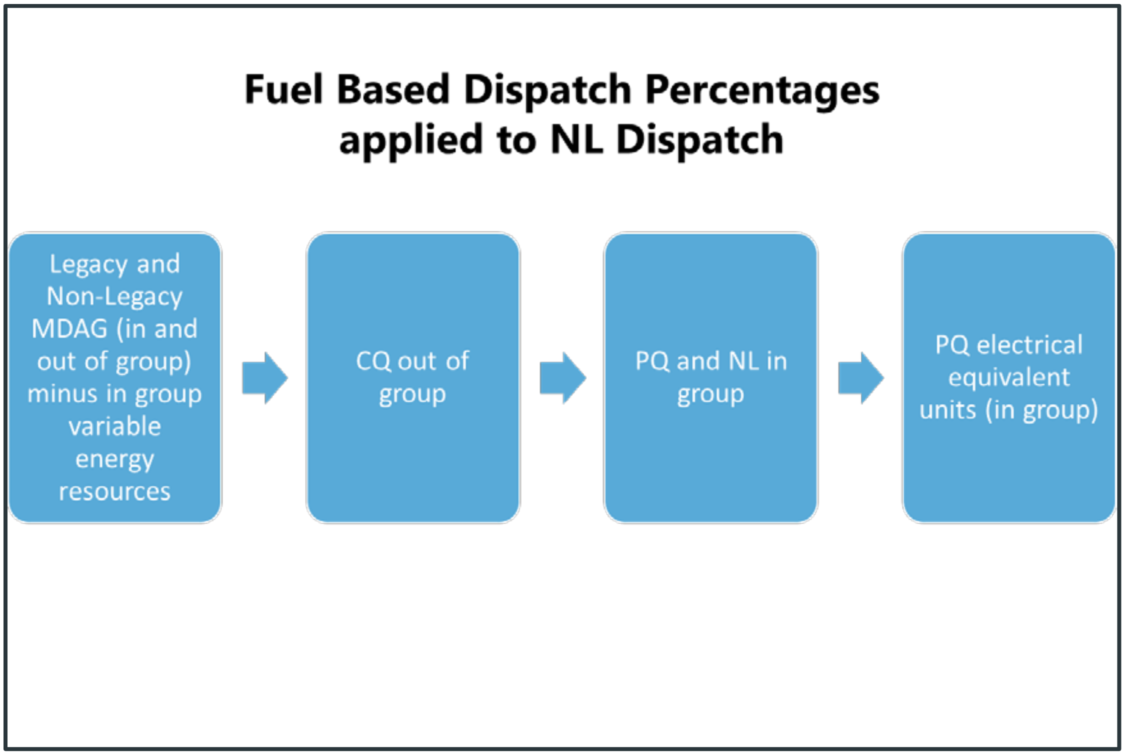
Fuel Type	In-Group						Out-Group					
	Summer Peak			Winter Peak			Summer Peak			Winter Peak		
	L	NL & PQ	CQ	L	NL & PQ	CQ	L	NL & PQ	CQ	L	NL & PQ	CQ
Combined Cycle	NC	100%	100%	NC	100%	100%	NC	NC	0%	NC	NC	0%
Combustion Turbine	NC	100%	100%	NC	100%	100%	NC	NC	0%	NC	NC	0%
Diesel Engine	NC	100%	100%	NC	100%	100%	NC	NC	0%	NC	NC	0%
Hydro	NC	50%	50%	NC	50%	50%	NC	NC	0%	NC	NC	0%
Nuclear	NC	100%	100%	NC	100%	100%	NC	NC	0%	NC	NC	0%
Storage	NC	100%	100%	NC	100%	100%	NC	NC	0%	NC	NC	0%
Coal	NC	100%	100%	NC	100%	100%	NC	NC	0%	NC	NC	0%
Oil	NC	100%	100%	NC	100%	100%	NC	NC	0%	NC	NC	0%
Waste Heat	NC	100%	100%	NC	100%	100%	NC	NC	0%	NC	NC	0%
Wind	NC	40%	100%	NC	45%	100%	NC	NC	20%	NC	NC	20%
Solar	NC	40%	100%	NC	10%	100%	NC	NC	40%	NC	NC	10%
Hybrid	See Hybrid Example											

L = MDAG legacy Request (pre-dates SPP GI Queue)
NL = MDAG Non-Legacy Request (have been studied in a GI process and are in the MDAG models)
PQ = Prior-Queued Requests under active study
CQ = Current-Queue Requests under active study
NC = No Change in dispatch from MDAG model (see notes below)
Percentages are based on the requested interconnection service amount in megawatts.
NOTE: Per the base sinking methodology, L or NL requests are included in the sink definition minus in-group high variable energy resources
NOTE: PQ and NL generators which are co-located with a CQ request (Electrically Equivalent) are dispatched at the same percentage of a CQ request (in-group only)
NOTE: Non-Legacy MDAG generators are firm and non-firm Variable Energy Resources (e.g., Solar and Wind) not dispatched in the MDAG model consistent with the SPP Model Development Procedure Manual.
NOTE: Non-Variable Energy Resources are assumed to have been consideredfor dispatch as needed in the MDAG model consistent with theSPP Model Development Procedure Manual; these resources will follow the Fuel Based Dispatch Table for Stability on a limited case-bycase basis.

If the proposed POIs of a non-Legacy MDAG generator or Prior-Queued Request and a Current-Queue Request are Electrically Equivalent, the non-Legacy MDAG generator or Prior-Queued Request will be dispatched at the In-Group Current-Queue Request amount. If the proposed POIs for any requests change between phases of study, then dispatch will be changed accordingly in the subsequent phases.

4.3.1.4.2 SINK GENERATION

In order to maintain gen-load balance within each planning region, the generation dispatched in the Source Generation section displaces MDAG Generation not included in the source. The following chart represents stability sink order:



The additional generation is offset by reducing the dispatch of Pre-Existing Generators across the entire SPP footprint excluding in-group Variable Energy Resources. Certain Resource types such as nuclear, hydro, etc. are excluded from the sink generation.

If minimum generation limits are reached when reducing MDAG generators, the following prioritized generation adjustments will be modeled as needed.

1. The current study requests out-of-group will be reduced from the percentages in Table 6 on a pro rata basis.
2. Non-Legacy MDAG generators and Prior-Queued Requests in-group will be reduced from the fuel-based dispatch percentages on a pro-rata basis excluding the fuel-based dispatch exception cases above.

Additional reductions will be determined on a case-by-case basis and may include reducing non-Legacy MDAG generators and Prior-Queued Request in-group from the fuel-based dispatch percentages on pro-rata basis meeting exception cases above, reducing Current-Queue Requests from the fuel-based dispatch percentages on pro-rata basis, turning off MDAG generators, and reducing generation external to SPP.

4.3.2 Stability Analysis

4.3.2.1 STABILITY FAULT EVENTS

For all stability models developed, a transient stability analysis will be performed to determine generator unit response due to fault events on the system.

For the stability analysis, unstable conditions will be addressed for transmission reinforcement for contingencies specified in the dynamic stability assessment for TPL-001-4 contingencies equivalent to P0, P1, P2.1-2.3, P4, and P5 as identified by SPP and the Transmission Owners. Higher depth contingencies (P6-P7) will be evaluated as necessary for the location of the generation for mitigations. Unsuccessful reclosing will be evaluated for the faulted loss of elements, excluding transformers, for a P1 and P6 event.

The transient stability analysis will evaluate:

- System stability in response to fault events
- Compliance of Current-Queued Requests and Prior-Queued Requests with FERC Order 661-A
- Adherence to the SPP Disturbance Performance Requirements
- Post event voltage recovery within the SPP voltage criteria

Fault events will include P1 events involving each network circuit segment connected within three levels of each Current-Study Request's POI as well as P4 and P6 events involving each network circuit connected within two levels of each Current-Study Request's POI[15]. A network circuit is comprised of each segment of sectionalized single (or double) circuits from substations or buses to accommodate generation and radial load. Each level includes all substations on the remote end of all network circuits. (i.e., 0 levels away from a line tap POI includes substations with at last 3 connected circuits on either end of the tapped circuit) Additionally, P1, P4, and P6 events on relevant regional or tie line facilities applicable to the study group will be evaluated. Each event should remove from service all elements that are expected to automatically disconnect for each event.

When system transient stability issues are identified, investigative analysis is first used to identify the cause of instability. Changed system conditions may uncover data/modeling issues with generator models of existing, PQ, or CQ generators. Dynamic model parameter review in conjunction with block diagrams is used to ensure there are no logic errors near the identified

[15] SPP reserves the right to include/exclude additional contingencies regardless of their level away from the request's point of interconnection.

system constraint. Generators may also be temporarily replaced with constant power devices (no dynamic response) to see if a generator model is the cause of the stability issue. This is to ensure that any identified issue is due to system deficiencies as opposed to data quality issues.

For verified system deficiencies, CQ generation that is found to materially impact verified system deficiencies will be included for cost-allocation for applicable mitigations. Material impact is evaluated by comparing system response with and without relevant CQ generation. If a material impact cannot be determined for studied generation due to deficiencies that are pre-existing, such as system collapse/ instability, then a less severe fault will be applied to determine said impact. Fictitious mitigations, such as VAR support, may be used to assist in evaluating a CQ generator's impact on pre-existing system deficiencies.

4.3.2.2 MITIGATIONS

Mitigation of stability issues, not also observed as a steady-state issue, will evaluate reduced fault duration and removal of reclose from the fault definition. Actual equipment settings and capabilities may provide reduced clearing times.

Evaluation of reduced clearing times and removal of reclose may be used to identify and determine whether mitigation is provided by existing equipment and settings or may be provided by a Network Upgrade to fault interrupting equipment (i.e., breakers and relays).

4.3.3 Short-Circuit Analysis

4.3.3.1 DISIS PHASE 1 SHORT-CIRCUIT RATIO CALCULATION

SPP calculates the short-circuit ratio using this formula and reports the results in DISIS Phase 1:

$$SCR_{POI} = \frac{SCMVA_{POI}}{MW_{VER}}$$

4.3.3.2 DISIS PHASE 2 SHORT-CIRCUIT FAULT CURRENT CALCULATION

Because sequence data in stability models is not comprehensive, SPP calculates three-phase fault currents for each bus using the models described in section 4.3.1.1 of this Business Practice. Transmission Owners review the results and may identify preliminary issues to SPP along with preliminary upgrades for inclusion in the report. The short circuit analysis assumes that all upgrades identified in the powerflow analysis are in-service unless otherwise noted in the individual group short-circuit results.

Preliminary results are refined in the Interconnection Facilities Study with any additional required upgrades and cost assignment identified at that time.

4.3.4 SCRCCT Analysis

DISIS powerflow models serve as the starting point for the SCRCCT analysis. The interconnection requests withdrawn in Decision Point 1 are removed from the models, but upgrades from the powerflow study are not included.

A short-circuit ratio (SCR) check is used to assess the voltage strength of the system. For DISIS studies, standard SCR, composite SCR (CSCR), and weighted SCR (WCSR) are analyzed to determine if additional analysis will be required. The Short Circuit Ratios are defined as:

$$SCR = \frac{Ssc}{MW}$$

$$CSCR = \frac{CSCMVA}{MWn}$$

$$WSCR = \frac{\sum_i^N SCMVA * MWi}{\sum_i^N MWi}$$

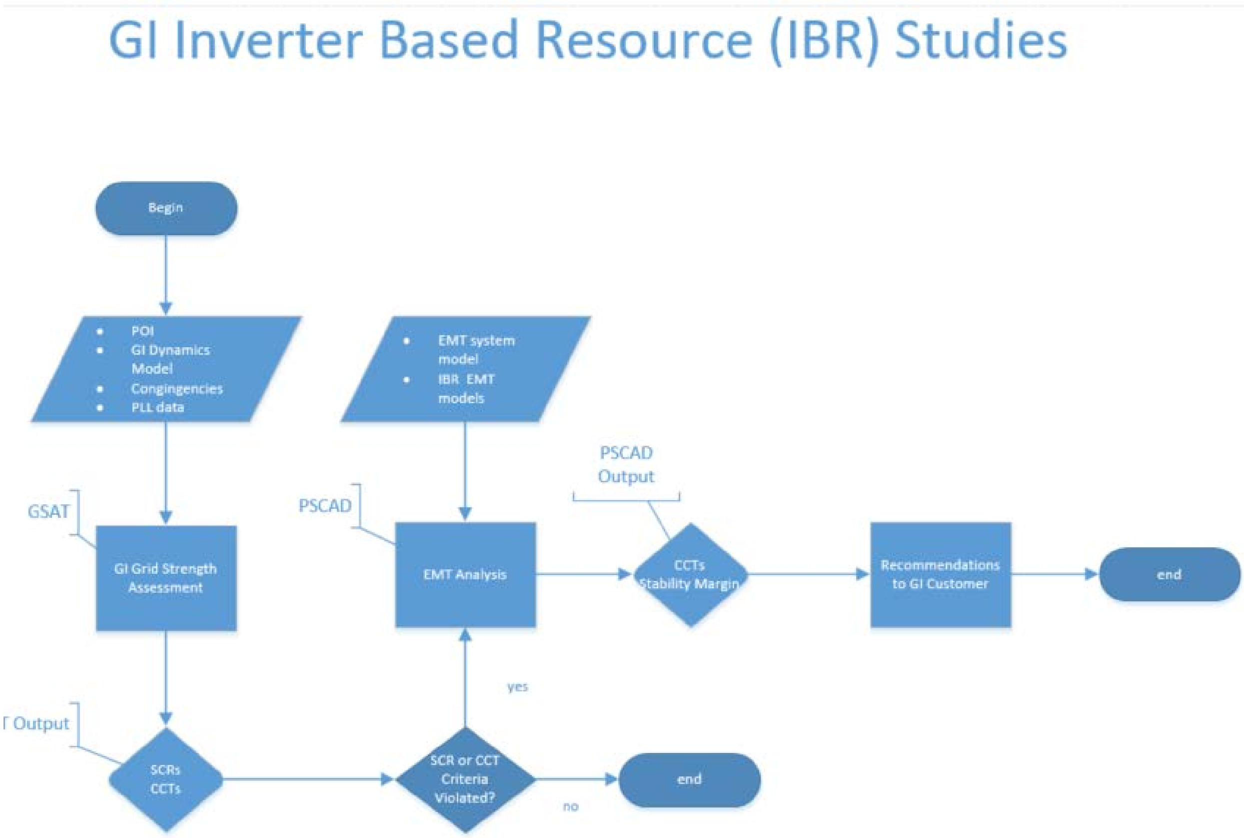
Ssc: Maximum Available Short Circuit Power (MVA) before connection of the resource.

MW: Power Rating (MW) of resource to be connected.

If any of the SCR calculations (SCR, CSCR, or WSCR) are below 6.0, project(s) will be deemed as failing the SCR check.

In addition to the SCRs, the critical clearing time (CCT) for faults near the POI of each project are screened. Critical Clearing Time is the maximum time a fault near the POI of an inverter-based resource is allowed to remain on the system such that the inverter-based resource remains stable. If the CCT for any project is below 0.15s (9 cycles), the project will be deemed as failing the CCT check.

The results of the SCRCCT and the WSCR are provided in the DISIS Phase 2 report. For any projects not passing SCR or CTT screening, a detailed Electromagnetic Transient (EMT) study will be performed to ensure system reliability and mitigations will be developed as applicable. This process is detailed in the following flowchart:



4.4 LIMITED OPERATION

As defined in the GIP Section 8.4.3, Limited Operation is a quantification of the amount of interconnection capacity available to the Interconnection Customer without system overloads, voltage violations, instabilities, or breaker over-duty prior to the in-service date of all identified upgrades. Limited Operation amounts are calculated for each request during the DISIS and are listed in the report.

For requests with NRIS, the steady-state LOIS value will be considered the higher value of the ERIS and NRIS values. The minimum value across the analyses performed (i.e. steady-state, stability) and constraint types observed (e.g. non-converged contingency, thermal constraints, voltage violations) will be set as the LOIS value. If short-circuit upgrades are necessary, that may be used for further refinement of LOIS values.

A LOIS value will be determined for each season in DISIS reports. DISIS reports will contain separate summer values based on the Year 2 and Year 5 models. Seasonal models will be mapped to corresponding operating date ranges according to Table 1, which is based on the SPP Model Development Procedure Manual[16], Section 3 Table 1.

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[16] SPP MDAG Reference Documents webpage (https://spp.org/spp-documents-filings/?id=18607)

Table 7: Seasonal Model Results to Operational Date Mapping

Operational Dates	HVER ERIS Steady State	LVER ERIS Steady State	NRIS Steady State	Stability
April 1 – May 31	Light Load	Lower of Summer Peak and Winter Peak	Light Load	Lower of Summer Peak and Winter Peak
June 1 – September 30	Summer Peak	Summer Peak	Summer Peak	Summer Peak
October 1 – November 30	Light Load	Lower of Summer Peak and Winter Peak	Light Load	Lower of Summer Peak and Winter Peak
December 1 – March 31	Winter Peak	Winter Peak	Winter Peak	Winter Peak

In cases where the summer peak seasons are referenced, summer operating dates prior to Year 5 will be based on the Year 2 summer peak LOIS value.

4.5 COST ALLOCATION

In accordance with GIP Section 4.2.2, cost allocation of Network Upgrades for Current-Study Requests that are wind are determined using the light load model. Cost allocation of Network Upgrades of all other Current-Study Request generator types is determined using the summer peak model. Cost allocation for all network upgrades is performed as defined below, regardless of which part of the study identified the upgrade.

UNIT TYPE	CASE USED
Wind	5-year Light Load
Non-Wind	5-year Summer Peak

For transmission circuit upgrades, an analysis is performed to determine the System-Intact TDF, also known as a Power Transfer Distribution Factor (PTDF) that each Current-Study Request had on each new upgrade. The PTDF is calculated on the group specific light load or summer peak model in which the project resides. The impact each Current-Study Request had on each upgrade project is weighted by the size of each request. In this case, the size of the request is the interconnection service amount MWs being requested for interconnection service (in other words queue value). Finally, the costs allocated to each Current-Study Request for a particular upgrade are then determined by allocating the portion of each request's impact over the impact of all affecting requests. The PTDF calculation uses the same source and sink methodology utilized in the Contingency Analysis sections 4.2.2.2, 4.2.2.3, and 4.2.2.4. Individual generator impacts are determined, rather than using cluster-based impacts. For upgrades mitigating constraints in multiple groups, all generators assigned to those constraints will share in the cost. Consistent with the above methodologies, the group and scenario specific to each unit will be used to calculate the PTDF and subsequent MW impact.

For example, assume there are three Current-Study Requests: X, Y and Z, responsible for the costs of Upgrade 1. Given their respective PTDFs for the upgrade have been determined, the cost allocation for Current-Study Request X for Upgrade Project 1 is found by the following set of steps and formulas:

- Determine an impact factor on a given project for all responsible GI requests:
  - *Request X Impact Factor on Upgrade 1 = PTDF (%)(X) * MW(X) = X1*
  - *Request Y Impact Factor on Upgrade 1 = PTDF (%)(Y) * MW(Y) = Y1*
  - *Request Z Impact Factor on Upgrade 1 = PTDF (%)(Z) * MW(Z) = Z1*
- Determine each request's allocation of cost for that particular project:
  - $Request\ X's\ Upgrade\ 1\ Cost\ Allocation(\$) = \frac{Network\ Upgrade\ 1\ Cost\ (\$) \times X1}{X1+Y1+Z1}$
- Repeat previous for each responsible Current-Study Request for each project.

For substation specific upgrades, such as new reactive devices, reconfigurations, etc., PTDFs cannot be calculated on a bus or node basis. Therefore, the PTDFs are generally checked on either the worst-case contingent element in the direction of system intact flow or on all circuits connecting to the location where the upgrade is installed where the highest absolute value PTDF of all the circuits is used to calculate the MW impact for each interconnection request for solutions resolving system intact non-converged and voltage constraints. The process then proceeds in alignment with the transmission circuit allocation process.

The cost allocation of each necessary Network Upgrade is determined by the size of each request and its impact on the given upgrade. This allows for the most efficient and reasonable mechanism for sharing the costs of upgrades. Costs assigned to each Current-Study Request are listed in the report.

4.5.1 Cost Estimates

SPP requests feedback and cost estimates from TOs for all assigned upgrades in the DISIS. All cost information submitted by TOs are incorporated into the study for accuracy. In the event that SPP does not receive a cost estimate, SPP-developed cost estimates based on historical data will be utilized.

4.5.2 Incremental Long-Term Congestion Rights

The SPP OATT provides Incremental Long-Term Congestion Rights (ILTCR) as compensation for the cost of Network Upgrades allocated for interconnection service.[17]

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[17] See SPP OATT Attachment J Section V (C). Generation Interconnection Related Network Upgrades

4.6 AFFECTED SYSTEMS COORDINATION

SPP maintains agreements with most neighboring Transmission Providers that define how impacts from Interconnection Requests are coordinated between systems. References and links to the individual agreements are listed in the Reference Documents section of this business practice. SPP coordinates with other Transmission Providers on a case-by-case basis. For interconnection to facilities owned by SPP Transmission Owners and other facility owners that are within the SPP Region, see the SPP as an Affected System section in this document.

When a neighboring entity studies DISIS requests' impact to the neighboring system, according to JOAs found in the Appendix section, the neighboring entity provides their report to SPP by the end of Phase 2. Therefore, at the end of Phase 2 a request should have their SPP DISIS result report and any AFS result report, if applicable. In the event the neighboring entity study results are not available, SPP will communicate the delay and continue with the SPP DISIS process regardless of AFS delay.

4.7 DISIS REPORT

SPP will post a DISIS results report that provides Current-Queued requests information about models, constraints, upgrades, and costs associated with the upgrades. Upgrades can be **contingent** (meaning, relies on a previous upgrade at no cost unless the higher queued request(s) associated with that upgrade withdrawals) or **current study** (meaning, upgrades associated with constraints that require mitigation, but for the current requests under study). **Interconnection costs** for current requests are reported as well.

DISIS Reports are located under 'Impact Studies' on OASIS:
https://opsportal.spp.org/Studies/Gen

SPP provides final study models along with the report that include the upgrade solutions and/or upgrade idevs.

4.8 FACILITY STUDY

Placeholder for Facility Study

4.9 RESTUDY/SENSITIVITY DUE TO WITHDRAWALS

Placeholder for Restudy/Sensitivity due to withdrawals

4.10 SPP AND STAKEHOLDER ACCOUNTABILITY

SPP and stakeholders will introduce steps to focus on accountability for timelines and milestones that consist of mechanisms designed to promote the timely exchanges of data, reviews, and approvals within the interconnection service study process.

4.10.1 Project Schedule

SPP will develop a project schedule for each cluster and successive study. This schedule will identify the timing, duration, and responsible parties for all data exchanges, reviews, and approvals required to complete the DISIS assessment. SPP will coordinate with SPP stakeholders in the development of this schedule and provide stakeholder updates on a frequent basis.

This schedule will be maintained by SPP and regularly reviewed at appropriate SPP stakeholder meetings to keep affected parties informed of upcoming milestones to ensure the timely completion of the planning process.

4.10.2 Interconnection Customer and Transmission Owner Reviews

The GI Modeling Task Force[18], under GIAG recommendations, improve model accuracy, help solve models, provide transparency, incorporate TPL methodology, and adjust powerflow solutions parameters (Area Interchange and Non-convergence). In order to implement these, SPP and the GI Modeling Task Force recommended the following critical times for ICs and TOs review throughout the study process:

1. Submission and Scoping Calls – SPP, ICs and TOs
    a. ICs and TOs are expected to coordinate prior to application submission.
    b. SPP receives the interconnection application and schedules scoping calls with SPP, ICs and TOs to review the interconnection request.
    c. ICs are expected to review SPP's GI Queue and ensure their application data, one-lines, DYRE files, etc. match each other at the time the request is submitted. There is a one-time cure period if deficiencies are identified.
    d. In cases where there is no viable date mutually agreed upon by the IC, TO, and SPP, email communications between these parties may be used to serve the purpose of a scoping call.
2. Model Review – SPP, ICs and TOs
    a. SPP will post BASE, PQ, and CQ cases for review.

[18] GI Modeling Task Force Discussion/Update GIAG Meeting Materials January 2022

b. TOs review ratings between latest planning model and GI study models and sign off for completing the model review process.

c. ICs review of POI, configuration, topology, impedance, and machine parameters/models for the interconnection requests and sign off for completing the model review process.

d. Failure to provide appropriate feedback during the Model Review period could lead to upgrade assignments.

3. Draft Report Review – SPP, ICs and TOs

    a. SPP will post a draft report** and create a window where ICs can submit questions and feedback to SPP. SPP GI Planning needs to provide responses/feedback to submitted questions in a timely fashion*. SPP will post the TDF values in the report.

4. SPP will use the GIAG meetings or separate results calls to talk about the proposed solutions, explaining the constraints, contingencies, flows, thermal and voltage issues. However, this action is not intended to open a window for ICs and TOs to submit alternative mitigations to the constraints, as it would add an additional level of time and complexity to develop a final portfolio of projects for each cluster*.

*As the schedule permits

**The draft report is a courtesy to improve the DISIS process

In all instances, SPP's Remedy Management System shall be utilized to submit feedback or questions to SPP.

Note that TO work to directly support DISIS tasks, such as attending scoping calls, responding to data requests, reviewing models, and developing cost estimates, are all study costs recoverable from respective DISIS cluster ICs under Attachment V of the SPP tariff.

5 INTERCONNECTION SERVICE FOR ENERGY STORAGE RESOURCES

This section describes procedures for processing and evaluating interconnection requests for energy storage resources (ESR) under SPP's Generator Interconnection Procedures (GIP).

5.1 APPLICABILITY

A request to interconnect an ESR to the SPP Transmission System shall be treated as an Interconnection Request under the GIP and does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery nor to receive electricity for the purpose of charging.

A request to add an ESR to an existing Generating Facility may be made either as a new request for Interconnection Service or as a new request for Surplus Interconnection Service.[19]

A request to modify an existing ESR that is prohibited from charging from the Transmission System so that it can charge from the Transmission System will be treated as a new request for the sole purpose of determining the reliability impact of charging from the Transmission System.

5.2 PROCESS

ESRs will be evaluated for reliability impacts to the SPP Transmission System in both discharging mode (as a generator) and charging mode (as a withdrawal). The evaluation of both modes of operation will be conducted as part of the applicable Interconnection Study under the GIP. The application for interconnection service will require the provision of information necessary to fully evaluate interconnection of ESR facilities.

5.3 DISCHARGE MODE

When evaluating the interconnection of an ESR as a generator, the ESR will be dispatched in the GI cluster study models in the following ways:

<u>Steady-State Power Flow Analysis</u>
Pursuant to the dispatch levels listed in Table 1, Table 2, and Table 3.

<u>Dynamic Simulation</u>
In the same way as other non-storage resources.

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[19] Subsequent to the acceptance of SPP's compliance filing under FERC Order 845

Short-Circuit Analysis
As a source with characteristic impedance of the device.

5.4 CHARGE MODE

The GI study process does not evaluate ESRs as load as that is assessed in a separate tariff process (Delivery Point Addition/Modification or Transmission Service). The GI study process may evaluate the interconnection facility upgrades required to connect. Evaluation of the ESR in charging mode will determine the Interconnection Facilities[20] necessary to accommodate charging activity at the requested maximum rate of charge specified by the customer. The customer shall also specify the maximum rate of charge capability of the ESR. If the requested maximum rate of charge is less than the maximum rate of charge capability, the customer shall specify the monitoring and control equipment necessary to ensure that the device does not exceed the requested maximum rate of charge when charging from the Transmission System. The necessary control technologies and protection systems shall be established in Appendix C of the executed, or requested to be filed unexecuted, GIA or Interim GIA, as applicable.

Network Upgrades that may be required to support charging activity will be identified in the applicable Transmission Service study in accordance with Part II or Part III of the tariff. Charging activity conducted without obtaining the appropriate transmission service reservation is prohibited and would constitute a default of the GIA.

The evaluation of the impact of the ESR in charging mode may be waived if the application meets these requirements:

- The application for interconnection service stipulates that the Generating Facility cannot take energy from the Transmission System when operating in charging mode, by either Self-Dispatch or at the direction of SPP.
- The application for interconnection service includes a description of the monitoring and control equipment that will be used to ensure that the Generating Facility cannot take energy from the Transmission System when operating in charging mode.

Normal auxiliary load required solely for the operation of the ESR is exempted from this requirement.

[20] As defined in Section 1 of the GIP, Interconnection Facilities include all facilities and equipment between the Generating Facility and the POI, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

6 SPP AS AN AFFECTED SYSTEM

6.1 BASIC PRINCIPLES OF APPLICABILITY

As set forth in Section 2.1 of Attachment V to the SPP Open Access Transmission Tariff (OATT), the GIP apply to the processing of Interconnection Requests to the Transmission System that are subject to FERC jurisdiction. Any generator interconnecting to the Transmission System where such interconnection is subject to FERC jurisdiction must submit an Interconnection Request pursuant to Attachment V of the SPP OATT.

6.2 EXCEPTIONS TO APPLICABILITY

This guideline serves to clarify application of the GIP by providing examples of instances where the GIP would not apply.

Examples include, but are not limited to instances where:

1. The Generating Facility will be a Qualifying Facility (QF) where the QF's total output will be sold to its host utility according to PURPA and subject to state jurisdiction.[21]
2. The Generating Facility will interconnect to a facility not already subject to the OATT at the time the request is submitted, whether or not it plans to make wholesale electric energy sales.[22]

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[21] Interconnection Customers claiming exemption from the GIP must provide documentation of Qualifying Facility FERC certification, substantiating state jurisdiction and documentation from the host that 100% of the output will be sold to the host utility at avoided cost. QFs intending to make third party sales are subject to FERC jurisdiction per Order 2003 and are appropriately studied as part of the GIP. See FERC Order No. 2003 at P 814 ("[T]he Commission has jurisdiction over a QF's interconnection to a Transmission System if the QF's owner sells any of the QF's output to an entity other than the electric utility directly interconnected to the QF. . . This jurisdiction applies to a new QF that plans to sell its output to a third party, and to an existing QF interconnected to a Transmission System that historically sold its total output to an interconnected utility or on-site customer and now plans to sell output to a third party."). See also FERC Order No. 2003 at P 813; FERC Order No. 2006-A at PP 100-102; PURPA 292.203.a (3); PURPA 292.303. No interconnection of a QF pursuant to the GIP affects or diminishes any substantive rights of the QF to assert non-FERC jurisdictional status at any time according to the requirements of the law.

[22] See FERC Order No. 2006 at PP 5, 8; FERC Order No. 2003 at P 804; FERC Order No. 2003-A at P 710; FERC Order No. 2003-C at P 51. At the time an Interconnection Request is made to interconnect to a non-jurisdictional facility, the interconnection is not subject to the GIP. After a Generation Facility that makes wholesale electric energy sales has been connected, the interconnection facility is now subject to an OATT for Interconnection Requests made after that time.

3. The Generating Facility will produce electric energy to be consumed only on the Interconnection Customer's site.[23]
4. The Generating Facility will be used to supply energy only to unbundled retail customers over local distribution facilities.[24]
5. Generating Facility will not operate in sustained parallel with the Transmission System. For purposes of this exception, "sustained parallel" applies to any Generating Facility which operates in synchronous operation with the electrical power system for 100msec or more.

6.3 SYSTEM STUDIES FOR NON-JURISDICTIONAL FACILITIES

Generator interconnections, not subject to the OATT, may still require studies to identify impacts on SPP's or the directly connected Transmission Owner's transmission system. The Transmission Owner will notify SPP of interconnection requests of 5 MW or more that are submitted directly to the Transmission Owner because they fall under the exemptions in this business practice; or are otherwise required by the Transmission Owner's processes to be studied pursuant to SPP's study process. SPP and/or the Transmission Owner will evaluate each interconnection request not subject to OATT requirements and will make the final determination whether the interconnection study will be performed by SPP and/or by the Transmission Owner. In instances where further study is warranted, such studies will be performed by the Transmission Owner or SPP, at the direction of the Transmission Owner. Non-jurisdictional generator interconnection customers may be required to enter into the appropriate study agreements with SPP to facilitate an affected system study agreement. Additionally, requests for non-jurisdictional generator interconnections may be required to be coordinated with SPP in accordance with NERC standards.

Although such studies may be performed within SPP's GIP for planning purposes, the non-jurisdictional generator interconnection customer will not be subject to the OATT.

In such instances, the following shall apply:

1. When notified, the Transmission Owner is responsible for conducting any required studies to determine if the request may impact the Transmission System.

[23] See FERC Order No. 2003 at P 805; FERC Order No. 2003-A at P 747, n. 173.

[24] Unbundled retail service over local distribution facilities is not under FERC jurisdiction. See FERC Order No. 2006 at PP 7-8 and n.8.

2. Should the Transmission Owner determine that the generator interconnection may impact the Transmission System, the Transmission Owner shall notify SPP of such impacts and provide to SPP any system impact studies that detail such impacts.
3. As an impacted system, SPP will determine what additional studies will be required to coordinate the impacts, up to and including studying the impact in the Definitive Interconnection System Impact Studies. The Transmission Owner/distribution provider shall require as a condition of interconnection with the interconnection customer that all SPP required studies be completed. The Transmission Owner/distribution provider shall have the option to enter into the applicable Affected System study agreements and to be financially responsible for such studies, or as a condition of interconnection, to require the interconnection customer to submit a request to enter the Definitive Interconnection System Impact Study process or other SPP study process as applicable.[25]
4. It shall remain the Transmission Owner's responsibility to complete any generator interconnection agreements in accordance with the Transmission Owner's generator interconnection procedures regarding the completion of Network Upgrades required on the Distribution System and on the Transmission Owner's transmission system.
5. If SPP's studies show that Network Upgrades are required on the Transmission System, the Transmission Owner/distribution provider shall have the option to enter into a facilities agreement with SPP or require, as a condition of interconnection, the interconnection customer to enter into a facilities agreement with SPP and any affected Transmission Owner(s)/distribution provider(s) to complete the Network Upgrades required on their Transmission System.
6. All Network Upgrades must be completed prior to operation of the Generating Facility, unless other mitigations have been approved by SPP before the Network Upgrades are completed.

[25] The Transmission Owner(s)/distribution provider(s) has the ability to pass-through the Interconnection Study costs to its customer.

7 SPECIAL STUDIES

7.1 SPECIAL STUDIES BASE MODEL SET

Analyses for special studies are performed on final DISIS Phase 2 or restudy model sets. The base model sets for special studies will transition at least annually, and the assumptions and methodologies consistent with the model set's DISIS will be used with exceptions noted in the respective study's section of this manual.

7.2 LIMITED OPERATION SYSTEM IMPACT STUDY

7.2.1 Objective

Limited operation system impact studies (LOSIS) are performed to determine a Generator Interconnection Request's (GIR) limited operation interconnection service (LOIS), which is Interconnection Service available to a GIR prior to assigned Network Upgrades being placed in-service. The DISIS identifies initial availability of LOIS for the GIRs in the respective cluster. If study assumptions have changed such that the LOIS could have materially changed from the amount shown in the DISIS or most recent LOSIS, a new LOSIS may be requested. The assignment of Interconnection Facilities, Network Upgrades, or cost allocation will not be re-evaluated via an LOSIS.

7.2.2 Applicability

In order for a GIR to enter into an LOSIS, the request's Interconnection Customer must submit a LOSIS study request and the following criteria must be met:

- The subject GIR must have an effective Generator Interconnection Agreement (GIA) not on suspension, *and*
- At least one of the subject GIR's associated Contingent Facilities or Network Upgrades is not expected to be in-service[26] by the request's Commercial Operation Date, *and*
- One of the following is true:
    - The current special studies model set differs from the request's latest DISIS or LOSIS results, *or*
    - There are relevant upgrades that have been placed in-service earlier than originally expected and would result in a material change in LOIS, *or*
    - The DISIS results were not reflective of the expected topology on the request's Commercial Operation Date (less relevant upgrades).

Considerations for the determination of relevant upgrades include, but are not limited to:

[26] Per SPP Quarterly Project Tracking Report

- The upgrades are referenced in the subject GIR's GIA (e.g. Contingent Facility, Shared Network Upgrade)
- An SPP Notification to Construct (NTC) has been issued to address the most limiting element related to the GIR's current LOIS amount
- An SPP NTC has been issued for a new outlet from the GIR's Point of Interconnection (POI)

7.2.3 Methodology

Requests included in the base model set will remain in the cases and available for dispatch. The LOSIS model will be dispatched with respect to the queue priority of the request's DISIS cluster.

If the relevant upgrades expected to be in-service by the request's Commercial Operation Date have changed since the analysis last determining the request's LOIS value, such upgrades will be included or excluded based on those expectations.

The powerflow and stability issues that may be used to determine the updated limited operation value will be limited to those observed or related to those observed in the request's DISIS report(s). Short-circuit results from the GIR's DISIS remain effective.

Seasonal LOIS values will be determined consistent with the DISIS limited operation methodology in the *4.4 Limited Operation* section of this manual.

Once the LOIS value is determined, the request's Generator Interconnection Agreement (GIA) will be amended to include the update. Limited operation values are subject to change via subsequent DISIS restudies and LOSIS.

7.2.4 Steady-State Analysis

After the study models are developed, SPP performs a contingency analysis on the Current-Queued model set to identify potential non-converged contingencies, thermal constraints, and/or voltage constraints.

If there are any non-converged contingencies or voltage constraints on which the request has a sufficient TDF (consistent with the DISIS), the steady-state LOIS value will be set at 0 MW.

If thermal constraints on which the request has a sufficient TDF are identified and no non-converged contingencies nor voltage violations are identified, the following equation will be used to determine the steady-state LOIS value:

$$LOIS_{SS} = MW_{Request} * \left(1 - \frac{Rating_{MVA} * (Loading_{PU} - 1)}{\sum(MW * TDF)_{Equally\ Queued\ Requests}}\right)$$

7.2.5 Stability Analysis

Stability analysis will be waived in the following cases:

- No stability issues related to the Request were indicated in the Request's DISIS or

- The model set used for the LOSIS is the same as the Request's DISIS model set and
    - Upgrades related to the Request are expected to be in-service sooner than assumed in the Request's DISIS or
    - Upgrades related to the Request are non-impedance changing (e.g. terminal upgrades, reactive devices).

For all stability models developed, a transient stability analysis will be performed to determine generator unit response due to fault events on the system. The faults taken and monitored system will be determined consistent with the respective DISIS process.

For system responses within the monitored system that do not meet the SPP Disturbance Performance Requirements, reducing the dispatch of the GIR in 25% increments of the maximum capacity may be tested to determine if stability is maintained at lesser values.

7.3 INTERIM AVAILABILITY SYSTEM IMPACT STUDY

7.3.1 Objective

Interim Availability System Impact Studies (IASIS) are performed to determine a request's Interim Interconnection Service (IIS) available on the request's Commercial Operation Date prior to its DISIS results. No Network Upgrades are assigned to a request via an IASIS.

7.3.2 Applicability

In order for a GIR to enter into an IASIS, the request's Interconnection Customer must submit an IASIS study request and the following criteria must be met:

- The request's respective DISIS Phase 2 must not have commenced because the DISIS Phase 2 results would be available at or near the same time as the IASIS results, and
- The expected posting of request's DISIS Phase 2 results are after the request's Commercial Operation Date.

If a GIR's Interconnection Customer elects to proceed with limited operation or Interim Interconnection Service by the end of DP2, final DISIS Phase 2 Limited Operation results may be used in place of an IASIS study if an IGIA could be put into effect before a GIA.

7.3.3 Methodology

Requests included in the base model set will remain in the cases and available for dispatch. Requests with an IGIA that are higher- or equally-queued to the interim request will be added to the models. The IASIS model will be dispatched with respect to the queue priority of the request's DISIS cluster.

Upgrades will be included or excluded based on whether or not they are expected to be in-service by the request's Commercial Operation Date.

Powerflow, stability, and short-circuit analyses will be performed to determine IIS available. Short-circuit ratio and critical clearing time (SCRCCT) analysis is also required for all inverter-based resources. The seasonal cases of the base DISIS model set up to and including year 5 will be developed and included in the analysis. The Annual Interim Study will capture any annual updates leading up to the Request obtaining full Service, until the request's DISIS is complete at which time their GIA will replace their IGIA.

Seasonal IIS values will be determined consistent with the DISIS limited operation[27] methodology in the *4.4 Limited Operation* section of this manual.

If the GIR's DISIS has not commenced, Affected Systems will be notified of IASIS requests via this process. The IASIS request may be subject to interconnection studies by Affected Systems.

If Interim Interconnection Service is available as determined by an IASIS, following the report posting, SPP will coordinate as appropriate with the interconnecting TO to perform a Facilities Study at the cost of the IC for the Interconnection Request's Interconnection Facilities in order for SPP to provide a draft IGIA to the IC unless the IC chooses to withdraw the Interim Interconnection Service request in writing.

If the IC chooses to proceed with the Interim Interconnection Service, the service would be granted via an IGIA. Interim Interconnection Service is subject to change via Annual Interim Studies. Once a GIA for the GIR is effective, the IGIA will no longer be effective.

7.3.4 Steady-State Analysis

After the study models are developed, SPP performs a contingency analysis on the Current-Queued model set to identify potential non-converged contingencies, thermal constraints, and/or voltage constraints.

The DISIS contingencies may be modified as needed to reflect topology changes introduced by the addition of interconnection facilities.

If there are any non-converged contingencies or voltage constraints on which the request has a sufficient TDF (consistent with the DISIS), the steady-state IIS value will be set at 0 MW.

If thermal constraints on which the request has a sufficient TDF are identified and no non-converged contingencies nor voltage violations are identified, the following equation will be used to determine the steady-state IIS value:

$$IIS_{SS} = MW_{Request} * \left(1 - \frac{Rating_{MVA} * (Loading_{PU} - 1)}{\sum(MW * TDF)_{Equally\ Queued\ Requests}}\right)$$

[27] "Interim Interconnection Service" can be used in place of any references to "Limited Operation Interconnection Service".

7.3.5 Stability Analysis

For all stability models developed, a transient stability analysis will be performed to determine generator unit response due to fault events on the system. The faults taken and monitored system will be determined consistent with the respective DISIS process.

For system responses within the monitored system that do not meet the SPP Disturbance Performance Requirements, reducing the dispatch of the GIR in 25% increments of the maximum capacity may be tested to determine if stability is maintained at lesser values.

7.3.6 Short-Circuit Analysis

The short-circuit analysis for IASIS is consistent with the DISIS process describes in section 4.3.3.2 of this business practice.

If the GIR is an inverter-based resource, an analysis to determine short-circuit ratio and critical clearing time (SCRCCT) will be performed. This analysis is a screening to help SPP determine if electromagnetic transient analysis is required. Threshold criteria for SCR and CCT in the DISIS will be used.

7.4 ANNUAL INTERIM STUDY

7.4.1 Objective

Annual Interim Studies are performed to update a request's IIS available on the request's Commercial Operation Date prior to its DISIS results. Because IASIS-determined IIS is determined before higher-queued interconnection service is granted via DISIS, as DISIS studies grant service, IIS values must be reassessed. Annual Interim Studies are performed annually, late in the year. No Network Upgrades are assigned to a request via an IASIS.

7.4.2 Applicability

A GIR will be included in the Annual Interim Study if the following criteria is met at the commencement of the study:

- The GIR has an effective IGIA, and
- The current special studies DISIS model set is later than the base DISIS model set used to determine the latest IIS value for the GIR, and
- The GIR's final DISIS Phase 2 results are not available.

7.4.3 Methodology

Requests included in the base model set will remain in the cases and available for dispatch. All requests with an IGIA will be added to the models. The Annual interim Study model will be dispatched with all study requests considered Current-Queued. The IASIS analysis methodologies will be used to determine powerflow, stability, and short-circuit issues and the corresponding seasonal IIS available to each study request. If multiple requests are impactful to common issues, IIS available will be reduced starting with the lowest queued requests first.

7.5 SURPLUS INTERCONNECTION SYSTEM IMPACT STUDY

7.5.1 Objective

The purpose of a Surplus Interconnection System Impact Study (SISIS) is to evaluate whether installing additional requested generation facilities to employ unutilized portions of granted Interconnection Service is a Material Modification. Proposed Surplus Generating Facilities (SGF) must not require any Network Upgrades unless permitted in the tariff.

7.5.2 Applicability

If a request's Interconnection Customer submits an SISIS study request, the following criteria must be met for the request to enter the SISIS process:

- The Existing Generation Facility (EGF) is a Legacy unit or has an effective GIA not on suspension and
- The EGF must have made its Surplus Interconnection Service available to the SGF if the EGF customer is not the same as the SGF customer and
- The EGF must have the same POI substation and voltage as the SGF and
- The EGF configuration must remain the same with the exception of accommodating the SGF interconnection[28].

SISIS requests are with respect to a single EGF, and in order to determine a single EGF with respect to a SISIS request, SPP may consider granularity of the respective GIA(s), market registration, planning models, and commission dates.

7.5.3 Methodology

An SISIS may consist of steady-state, stability, and short-circuit analyses. The Surplus Interconnection Service Impact Study shall consist of reactive power, short circuit/fault duty, stability analyses, and any other appropriate studies. Steady-state analyses may be performed as necessary to ensure that all required reliability conditions are studied. If the existing Interconnection Service was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service.

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[28] If other changes to the EGF or its Interconnection Facilities are proposed, the EGF's Interconnection Customer must request an MRIS and the changes must be deemed not a Material Modification prior to the SISIS.

7.5.4 Steady-State Analysis

If the EGF was dispatched to its full capacity and/or its interconnection service amount (100%) in all its DISIS group-specific powerflow models, powerflow analysis will not be applicable. If the EGF is a Legacy unit, powerflow analysis will not be applicable. If powerflow analysis is performed, the group-specific seasons in which the EGF was not dispatched to 100% will be assessed with the SGF at its maximum output; if at maximum output, the POI injection exceeds the Interconnection Service amount, the SGF will be reduced such that the injection does not exceed Interconnection Service.

7.5.5 Stability and Short-Circuit Analysis

At least two stability scenarios will be developed and assessed:

- The SGF dispatched at 100% and the EGF turned off
- The SGF dispatched at 100% and the EGF dispatched to set the POI injection to the Interconnection Service amount of the EGF.

Additional scenarios may be developed considering study-specific rationale including, but not limited to, dispatch of other SGFs of the EGF.

A dynamic stability analysis will be utilized to identify the impact of the surplus request. The analysis will be performed according to SPP's Disturbance Performance Requirements utilizing the details provided in the generation surplus request. A No-Fault and Fault analysis will be performed that includes a three-phase fault at the Interconnection Request's point of interconnection to confirm that no errors exist in the initial conditions of the system and the dynamic data.

The short circuit analysis will include applying a three-phase fault on buses up to five levels away from the POI bus. The short circuit analysis will utilize the PSS®E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module to calculate the fault current levels with and without the generation request online.

7.6 GENERATING FACILITY REPLACEMENT EVALUATION

7.6.1 Objective

The purpose of a Generating Facility Replacement Evaluation (GFRE) is to evaluate the impact on SPP facilities of a request for Generating Facility Replacement pursuant to the SPP Generator Interconnection Procedures (GIP) contained in Attachment V of the SPP tariff. Replacements include one or more generating units and/or storage devices (EGF) that will be replaced with one or more new generating units and/or storage devices at the same POI. GFRE may be result in identification of a Material Modification if the replacement is determined to have a material adverse impact on the Transmission System.

GFRE is a separate process from the retirement process detailed in SPP tariff Attachment AB.

7.6.2 Applicability

For a GFRE to be performed on an Existing Generating Facility, the requirements in Attachment V, Section 3.9.1 of the Tariff must be met.

One of more RGFs can replace one or more EGFs, but individual retirement and commission dates must meet the timeline requirements in the GIP.

7.6.3 Methodology

A GFRE consists of two studies: a Reliability Assessment Study and Replacement Impact Study.

The Reliability Assessment Study compares the conditions of the Transmission System when the EGF is taken offline to the conditions of the Transmission System when the EGF is online. This is to evaluate the performance of the Transmission System during the period between the EGF being taken offline and the Commercial Operation Date of the RGF. Business Practice 7800 outlines this process. Non-transmission mitigations are required for any valid issues observed in the Reliability Assessment Study.

The Replacement Impact Study will determine if the RGF has a material adverse impacts on the Transmission System when compared to the EGF. This may include steady-state analysis, stability analysis, and short-circuit analysis to ensure reliability. A Replacement Impact Study may deem the Generator Replacement a Material Modification if such a material adverse impact is determined to exist. The Steady-State Analysis and Stability and Short-Circuit Analysis sections below detail that of the Replacement Impact Study only.

7.6.4 Steady-State Analysis

If the EGF was dispatched to its full capacity and/or its interconnection service amount (100%) in all its DISIS group-specific powerflow models, powerflow analysis will not be applicable. If the EGF is a Legacy unit, powerflow analysis will not be applicable. If powerflow analysis is performed, the group-specific seasons in which the EGF was not dispatched to 100% will be assessed with the RGF at its maximum output; if at maximum output, the POI injection exceeds the Interconnection Service amount, the RGF will be reduced such that the injection does not exceed Interconnection Service.

7.6.5 Stability and Short-Circuit Analysis

A dynamic stability analysis will be utilized to identify the impact of the replacement request. The analysis will be performed according to SPP's Disturbance Performance Requirements utilizing the details provided in the generation surplus request. A No-Fault and Fault analysis will be performed that includes a three-phase fault at the Interconnection Request's point of interconnection to confirm that no errors exist in the initial conditions of the system and the dynamic data.

The short circuit analysis will include applying a three-phase fault on buses up to five levels away from the POI bus. The short circuit analysis will utilize the PSS®E "Automatic Sequence Fault

Calculation (ASCC)" fault analysis module to calculate the fault current levels with and without the RGF online.

7.7 MODIFICATION REQUEST IMPACT STUDY

7.7.1 Objective

The purpose of a Modification Request Impact Study (MRIS) is to determine whether a customer-proposed change to an Interconnection Request or portion of an Interconnection Request, other than those permissible under Attachment V, Section 4.4.1, is classified as a Material Modification.

7.7.2 Applicability

If an IC is proposing changes to an Interconnection Request with an effective GIA, IGIA, or Surplus GIA (SGIA) or Existing Generating Facility that changes data requested in a Study Agreement or Interconnection Request web application (e.g. unit ratings, reactance data, transformer data), and changes do any of the following, then the MRIS process is not applicable:

1. Retire, permanently remove from service, or replace any of the Generating Facility's generators or storage devices that have reached commercial operation[29];
2. Change the Interconnection Request's POI substation or voltage level; or
3. Change the technology type (e.g. wind, solar, combustion turbine) such that the powerflow dispatch of the Interconnection Request has not been studied via the respective DISIS steady-state analysis (for non-Legacy units).[30]

Proposed post-GIA changes that meet Modification Request Impact Study criterion 2 or 3 are not permissible.

If an Interconnection Request is not yet modeled in the current special studies base model set and the request does not have an effective IGIA or SGIA[31], the request for change will be studied after the transition to a special studies base model set that includes the study request. If the Interconnection Request is requesting a technological advancement, an MRIS may be required as determined by SPP pursuant to GIP section 4.4.5.If no analysis is needed as determined in the *Stability and Short-Circuit Analysis* section below or in cases where a change does not require an MRIS, any modification to information contained in an Interconnection Request or its associated

[29] If any part of the Generating Facility that has reached commercial operation is being proposed as retired, permanently removed from service, or replaced, the Generating Facility Replacement Evaluation or Attachment AB process should be considered

[4] For example, if an Interconnection Request was studied dispatched at 100% in all HVER cases and the modified technology type is dispatched at 100% in a subset of HVER cases, this is permitted because the power flow of that dispatch level has already been studied in all applicable cases via DISIS. However, in the case that an Interconnection Request was only studied dispatched at 100% in HVER cases and the modified technology type results in a dispatch of 100% in the LVER cases, this has not been studied via DISIS and is therefore not permitted.

[31] In cases where the Interconnection Request has an IGIA or SGIA, other model sets that include the request, such as the Annual Interim Study or SISIS models, may be used.

GIA, including modifications to Interconnection Facilities, should be reported to SPP to determine whether the change is permitted and if the GIA should be amended.

7.7.3 Methodology

The MRIS will determine if the proposed changes to the Interconnection Request are a Material Modification. An MRIS may result in the proposed changes being deemed a Material Modification if a material adverse impact is present in the study case compared to the pre-study case. This may include stability analysis and short-circuit analysis to ensure reliability. If the proposed changes are still desired after being determined to be a Material Modification, a new Interconnection Request is required.

7.7.4 Stability and Short-Circuit Analysis

A dynamic stability analysis will be utilized to identify the impact of the proposed changes to the Interconnection Request if the proposed changes include any of the following:

- Greater than a 10% change in total impedance of the Interconnection Request and its Interconnection Facilities since the last time the Interconnection Request was studied for stability in an MRIS study, or the request's DISIS cluster and group was studied for stability[32];
- A change to the Interconnection Request's dynamic model; or
- Changes to the parameters associated with the Interconnection Request's dynamic model.

The analysis will be performed according to SPP's Disturbance Performance Requirements utilizing the details provided in the MRIS request. A No-Fault and Fault analysis will be performed that includes a three-phase fault at the Interconnection Request's POI to confirm that no errors exist in the initial conditions of the Transmission System and the dynamic data. If any issues that are present in the study case are not in the base case and attributable to the study modifications, those study modifications will be deemed a Material Modification.

The short circuit analysis will include applying a three-phase fault on buses up to five levels away from the POI bus. The short circuit analysis will utilize the PSS®E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module to calculate the fault current levels with and without the RGF online.

[32] If the impedance of the Interconnection Request and its Interconnection Facilities are the only change being proposed and the customer has determined that it does not exceed a 10% difference, evidence can be provided to SPP for review to determine the need for an MRIS.

8 REFERENCE DOCUMENTS

Reference materials and links are available at the sites below:

- SPP Open Access Transmission Tariff[33]
  - Generator Interconnection Procedures (Attachment V)
- SPP Business Practices[34]
- Seams Agreements[35]
  - Associated Electric Cooperatives, Inc.
  - California Independent System Operator Corporation
  - Electric Reliability Council of Texas
  - Midcontinent Independent System Operator, Inc
  - Peak
  - Public Service Company of Colorado
  - Saskatchewan Power Corporation
  - Southwestern Power Administration
  - Tennessee Valley Authority
- SPP Disturbance Performance Requirements[36]
- SPP Quarterly Project Tracking Report[37]
- Request Management System[38]
- New Three Stage Interconnection Process[39]
- ITP Manual location[40]
- SPP Model Development Procedure Manual location[41]

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33 https://spp.etariff.biz:8443/viewer/viewer.aspx

34 https://www.spp.org/spp-documents-filings/?id=18162

35 https://www.spp.org/spp-documents-filings/?id=18378

36 https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf

37 https://spp.org/spp-documents-filings/?id=18641

38 https://spprms.issuetrak.com/login.asp

39 https://opsportal.spp.org/documents/studies/SPP%20Three%20Stage%20Process%20Overview%202019-05-31.pdf

40 https://www.spp.org/engineering/transmission-planning/

41 https://spp.org/spp-documents-filings/?id=18607

9 LIST OF ACRONYMS

Acronym	Term
DF	Distribution Factor
DP	Decision Point
ERIS	Energy Resource Interconnection Service
ESR	Energy Storage Resource
EHV	Extra-High Voltage (300kV or higher)
FCITC	First Contingency Incremental Transfer Capability
FERC	Federal Energy Regulatory Commission
FS	Financial Security
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GIP	Generator Interconnection Procedures
GIR	Generator Interconnection Request
GSU	Generator Step-Up
HV	High Voltage (300kV or lower)
HVER	High Variable Energy Resource
IC	Interconnection Customer
IFS	Interconnection Facilities Study
ITP	Integrated Transmission Planning
LVER	Low Variable Energy Resource
MUST	Managing and Utilizing System Transmission
NERC	North American Electric Reliability Corporation

NRIS	Network Resource Interconnection Service
NTC	Notification to Construct
OATT	Open Access Transmission Tariff
PCWG	Project Cost Working Group
POI	Point of Interconnection
PSS/E	Power System Simulator for Engineering
PTDF	Power Transfer Distribution Factor
RMS	Request Management System
SPP	Southwest Power Pool
TO	Transmission Owner
TPL	[NERC] Transmission System Planning Performance Requirement
VER	Variable Energy Resource