NIPSCO

Part 1. Identification and Certification

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Miles Taylor 3-24-24
Miles Taylor — Date
Manager Electric System Planning

Part 2. Power Flow Base Cases

Northern Indiana Public Service Company LLC submits the following base cases as part of the 2024 FERC FORM 715. These cases were developed under the 2023 Series of the Eastern Interconnection Reliability Assessment Group ("ERAG") Multiregional Modeling Working Group ("MMWG") process and are used as a starting point for transmission planning studies.

Case 3	Abbreviation
2024 Spring Light Load	2024SLL
2024 Summer	2024SUM
2024/25 Winter	2024WIN
2025 Spring Light Load	2025SLL
2025 Summer	2025SUM
2025/26 Winter	2025WIN
2028 Spring Minimum Load	2028SML
2028 Summer	2028SUM
2028 Summer Shoulder	2028SSH
2028/29 Winter	2028WIN
2033 Summer	2033SUM
2033/34 Winter	2033WIN

TRANSMISSION PLANNING ASSESSMENT METHODOLOGY AND CRITERIA

For Compliance with NERC Reliability Standard: TPL-001-5

11/22/2022
Version: 5.1

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1 REVISION AND APPROVAL HISTORY

This document shall be revised and updated as needed to incorporate changes in methodology and criteria and to reflect changes to the approved NERC Standard requirements.

1.1 REVISION HISTORY

Version	Date	Author	Supervisor	Comments
1.0	10/14/2011	Dawn Quick	Robert Fox	Initial document load into the DMS.
2.0	12/31/2012	Dawn Quick	Robert Fox	Annual Review. Seasonal Ratings defined. Internal Communication additions.
3.0	07/18/2013	Dawn Quick	Robert Fox	Add Generator Interconnection Section.
3.1	10/15/2013	Dawn Quick	Robert Fox	Add language for Single Breaker Ratings.
3.2	12/26/2013	Dawn Quick	Robert Fox	Annual Review. No Changes
3.3	03/10/2014	Dawn Quick	Ganesh Velummylum	Annual Review. Section 4.5. Added footnote pertaining to Distribution Factor. Added Specification of NERC categories and Cases to study.
4.0	10/07/2015	Dawn Quick	Lynn Schmidt	Annual Review. Format and Content Changes to align with new TPL Standard
4.1	01/10/2016	Dawn Quick	Lynn Schmidt	Annual Review.
4.2	01/10/2017	Dawn Quick	Lynn Schmidt	Annual Review.
4.3	01/10/2018	Dawn Quick	Lynn Schmidt	Annual Review. Change in document review/revision requirements.
4.4	03/09/2018	Dawn Quick	Lynn Schmidt	Addition of 765kV Voltage Criteria
4.5	05/29/2019	Dawn Quick	Lynn Schmidt	Addition of Energy Storage Interconnection Criteria
4.6	02/06/2020	Dawn Quick	Lynn Schmidt	Added P5 to Facility Connection Criteria
4.7	05/27/2020	Dawn Quick	Lynn Schmidt	GI Cumulative Impact criteria revision
4.8	01/14/2021	Dawn Quick	Lynn Schmidt	Addition of solar plant study criteria. Revision of wind machine voltage criteria
4.9	10/28/2021	Dawn Quick	Lynn Schmidt	Addition of GI power factor criteria
4.10	11/08/2021	Dawn Quick	Lynn Schmidt	Revision of Storage Facility Connection Criteria
4.11	09/09/2022	Dawn Quick	Lynn Schmidt	Revision of voltage criteria
5.0	10/06/2022	Dawn Quick	Lynn Schmidt	Format and Content Changes to align with new TPL-001-5 Standard
5.1	11/22/2022	Dawn Quick	Lynn Schmidt	Revision of Energy Storage Interconnection Criteria

1.2 APPROVAL

Version	Supervisor	Title	Electronic Signature Date
1.0	Robert Fox	Leader Transmission Planning	9/28/2011
2.0	Robert Fox	Leader Transmission Planning	12/31/2012
3.0	Robert Fox	Leader Transmission Planning	7/18/2013
3.1	Robert Fox	Leader Transmission Planning	10/15/2013
3.2	Robert Fox	Leader Transmission Planning	12/26/2013
3.3	Ganesh Velummylum	Manager Electric System Planning	3/10/2014
4.0	Lynn Schmidt	Leader Transmission Planning	10/07/2015
4.1	Lynn Schmidt	Leader Transmission Planning	1/10/2016
4.2	Lynn Schmidt	Leader Transmission Planning	01/10/2017
4.3	Lynn Schmidt	Leader Transmission Planning	01/10/2018
4.4	Lynn Schmidt	Leader Transmission Planning	03/09/2018
4.5	Lynn Schmidt	Leader Transmission Planning	05/29/2019
4.6	Lynn Schmidt	Leader Transmission Planning	02/06/2020
4.7	Lynn Schmidt	Leader Transmission Planning	05/27/2020
4.8	Lynn Schmidt	Leader Transmission Planning	01/14/2021
4.9	Lynn Schmidt	Leader Transmission Planning	10/28/2021
4.10	Lynn Schmidt	Leader Transmission Planning	11/08/2021
4.11	Lynn Schmidt	Leader Transmission Planning	09/09/2022
5.0	Lynn Schmidt	Leader Transmission Planning	10/06/2022
5.1	Miles Taylor	Manager Electric System Planning	11/22/2022

2 ANNUAL PLANNING ASSESSMENT

Transmission Planning shall prepare an annual Planning Assessment of the performance of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated below), shall document assumptions, and shall document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. This assessment shall be performed for both the Near-Term and the Long-Term Transmission Planning Horizons. [R2]

Past studies may be used to support the Planning Assessment if they meet the following requirements:

- For steady state, short circuit, or stability analysis: the study shall be five calendar years old or less, unless a technical rationale is provided to demonstrate that the results of an older study are still valid. [R2.6.1]
- For steady state, short circuit, or stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included in the written assessment. [R2.6.2]

For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the required performance criteria, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the required performance criteria. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. [R2.7] [R2.8]

The Corrective Action Plan(s) shall:

- List System deficiencies and the associated actions needed to achieve required System performance. [R2.7.1] [R2.8.1]
- For Steady state and Stability Studies, include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. [R2.7.2]
- Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. [R2.7.4] [R2.8.2]

When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0 (steady state only), P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment. NIPSCO Transmission Planning shall evaluate its current stock and procurement strategy annually. Conclusions of this evaluation shall be stated in the assessment report. [R2.1.5][R2.4.5]

In accordance with TPL-001-5 R7, NIPSCO has executed a Coordination Agreement with MISO identifying individual and joint responsibilities for performing the required studies. NIPSCO has not delegated any of their TPL responsibilities to MISO. In addition to any data requests made by MISO required to fulfill their TPL requirements, NIPSCO will also provide results from its Short Circuit studies to MISO. [R7]

Transmission Planning shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Recipients of the Planning Assessment includes: MISO, PJM, METC, Duke, and Ameren. [R8] [R8.1]

2.1 Model Data

NIPSCO Transmission Planning shall maintain System models within the NIPSCO area for performing the studies needed to complete its Planning Assessment. The models are consistent with provisions of the most recent Multiregional Modeling Working Group Procedure Manual and the most recent MOD-32 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. [R1].

System Models Represent:

- Existing Facilities
- New planned Facilities and changes to existing Facilities
- Real and reactive Load forecasts
- Known commitments for Firm Transmission Service and Interchange
- Resources (supply or demand side) required for Load

A project is considered “planned” and is modeled in the base cases when a continuing need has been identified by recent and past study results. The planned project, in general, is needed in the near term and typically has budget approval for engineering or material costs.

A “proposed” project is typically not modeled in base cases. The “proposed” project is being studied for continuing need and timing when project lead time is sufficient. A “proposed” project may also be conceptual in nature. It has been identified as a possible solution in long term studies where violations may be marginal. It may also be identified as a possible solution to stressed or alternative dispatch cases. Alternative projects may be studied for best solution. Proposed projects are given a “planned” status after need has been proven, taking into consideration sufficient lead time.

2.2 *STEADY STATE*

In accordance with NERC Standard TPL-001-5, the following system conditions are required for study annually:

- System peak Load for either Year One or year two, and for year five. [R2.1.1]
- System Off-Peak Load for one of the five years [R2.1.2.]
- A current study assessing expected System Peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. [R2.2.1]

For each of the Near-Term studies described above, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment will vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response: [R2.1.3]

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.2.1 Contingency Analysis

For the steady state portion of the Planning Assessment, Transmission Planning shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons mentioned above. The studies shall be based on computer simulation models using data provided in accordance with TPL-001-5 Requirement R1. [R3]

A list of those Contingencies to be evaluated for System Performance for Planning Events shall be created corresponding to the Planning Events P0-P7 listed in Table 1. For steady state, all planning events are simulated unless contingency outages duplicate the same elements as those of another contingency. Additionally, a list of select known outages for the near term shall be created and their impact assessed for the system peak or Off-Peak conditions that they are expected to experience when the outage is planned. Simulations shall be performed on each selected known outage event for the P0 and P1 categories listed in Table 1. Results of these simulations should be assessed to determine whether the BES meets the performance requirements in section 2.2.2. [R2.1.4][R3.1] [R3.4]

A list of Contingencies for those extreme events listed in Table 1 that are expected to produce more severe System impacts shall be identified and created. For Steady-State, all extreme events listed in Table 1, extreme events #1 and #2 shall be simulated. Wide-area events affecting the Transmission System, such as those described in Table 1, extreme events #3, may be evaluated. A description and rationale of these wide-area events, if included, will be documented in the assessment. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. [R3.2] [R3.5]

Transmission Planning shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. [R3.4.1]

Contingency analysis shall simulate the removal of all elements that the Protection System and other automatic controls that are expected to normally clear or disconnect for each Contingency without operator intervention. [R3.3.1]

The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Synchronous generator terminal voltages will be monitored at *85%* for potential tripping. Solar and Wind machine terminal voltages will be monitored at 90% for potential tripping. [R3.3.1.1]
- Tripping of Transmission elements where relay loadability limits are exceeded. A tripping proxy of 125% of Emergency Rating will be used for all lines and transformers. When exceeded, Transmission Planning will consult Protection Engineering to obtain actual trip values and determine if a corrective action plan is necessary. [R3.3.1.2]

Contingency analysis shall simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. [R3.3.2]

2.2.2 Steady-State Performance Requirements and Criteria [R5]

- Voltages, post-contingency voltages, and post-contingency voltage deviations shall be within acceptable limits. See Steady-State Voltage Tables below.
- Applicable Facility Ratings shall not be exceeded. Transmission Planning establishes Normal and Emergency Facility Ratings for summer and winter seasonal periods based on its documented Facility Rating Methodology. Single Breaker Ratings are also established for use in studies where the contingency may cause a facility to have a more limited rating.
- The transmission system shall not experience uncontrolled cascading or islanding. Load loss shall not exceed 300 MWs, excluding consequential load. See section 2.5, Supplemental Performance Analysis. [R6]
- Synchronous generators are projected to trip when the terminal voltage is below 85%. Solar and Wind machines are projected to trip when the terminal voltage is below 90%. [R3.3.1.1]
- Consequential Load Loss as well as generation loss is acceptable as a result of any event excluding category P0 No Contingency.
- The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady-state performance requirements.

<u>Steady-State Voltage Tables</u>

Location	Normal Condition		Post-Contingency Steady-State		
	Minimum	Maximum	Minimum	Maximum	Deviation
765 kV buses	92%	105%	90%	105%	+/- 10%
345 kV buses	92%	105%	90%	105%	+/- 10%
138 kV buses	92%	105%	90%	105%	+/- 10%
69 kV buses	94%	105%	92%	105%	+/- 10%
On-Line Synchronous Generator Terminals [3.3.1.1]	95%	110%	85%	110%	+/- 10%
On-Line Solar + Wind Machine Terminals [3.3.1.1]	95%	110%	90%	110%	+/- 10%

Location	Normal Condition		Post-Contingency Steady-State		
	Minimum	Maximum	Minimum	Maximum	Deviation
Customer Substation 138kV Buses	95%	105%	90%	110%	+/- 10%

2.3 *STABILITY*

In accordance with NERC Standard TPL-001-5, the following system conditions are required for study annually:

- System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. [R2.4.1]
- System Off-Peak Load for one of the five years. [R2.4.2]

For each of the studies described above, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: [R2.4.3.]

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability
- Generation additions, retirements, or other dispatch scenarios.

For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies and shall include documentation to support the technical rationale for determining material changes. [R2.5]

Loads shall be modeled by P (constant current) and Q (constant impedance) which represents the aggregate overall dynamic load behavior. For sensitivity analysis, loads may be modeled by a composite load model considering more detailed behavior of induction motor loads. [R2.4.1]

2.3.1 Contingency Events

For the Stability portion of the Planning Assessment, Transmission Planning shall perform the Contingency analyses for the Near-Term and Long-Term Planning Horizons mentioned above. The studies shall be based on computer simulation models using data provided in accordance with TPL-001-5 R1. [R4]

A list of those Contingencies to be evaluated for System Performance for Planning Events shall be created corresponding to the Planning Events P0-P7 listed in Table 1. Additionally, select known outages for the near term shall be created and their impact assessed for the system peak or Off-Peak conditions that they are expected to experience when the outage is planned. Simulations shall be performed for the P1 categories listed in Table 1. For transient stability, Planning Events and select known outages for transmission facilities directly associated to an individual power plant as well as Planning Events for other selected transmission facilities are simulated. [R2.4.4][R4.4]

Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated for impact to the BES. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. [R4.2] [R4.5]

Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. [R4.4.1]

Contingency analyses shall simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. [R4.3] [R4.3.1]

The contingency analyses shall include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized. [R4.3.1.1]
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. [R4.3.1.2]
- Tripping of Transmission lines and transformers where transient swings will cause a Protection System operation based on generic or actual relay models. [R4.3.1.3]

Contingency analyses shall simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, synchronous condensers, static var compensators, power flow controllers, and DC Transmission controllers. [R4.3.2]

Studies shall be performed for planning events to determine whether the BES meets the following stability performance requirements and criteria: [R4.1] [R4.2]

2.3.2 Stability Performance Requirements and Criteria [R5]

The transmission system shall not experience uncontrolled cascading or islanding.

For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. [R4.1.1]

For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. [R4.1.2]

For planning events P1 through P7: Power oscillations shall exhibit acceptable damping. Observed damping ratio (ζ) shall be greater than 0.020. [R4.1.3]

Synchronous Generator Voltage: Voltages at the terminal bus of on-line synchronous generators shall return to the allowable steady-state contingency voltage within five seconds after fault clearing. [R4.3.1.2]

Solar Generating Plant Voltage: Solar plants shall have low voltage ride-through capability monitored at the high-side GSU terminal down to 0% of the rated voltage for 0.150 seconds (9.0 cycles) for three-phase faults and down to 0% of the rated voltage for 0.433 seconds (26.0 cycles) for single-line ground faults. [R4.3.1.2]

Wind Generating Plant Voltage: Wind plants shall have low voltage ride-through capability monitored at the high-side GSU terminal down to 0% of the rated voltage for 0.150 seconds (9.0 cycles) for three-phase faults (Per FERC Order 661-A) and down to 0% of the rated voltage for 0.433 seconds (26.0 cycles) for single-line ground faults. [R4.3.1.2]

Load Bus Voltages: Voltages at load buses should return to the allowable steady-state contingency voltage within five seconds after fault clearing.

2.4 *Short Circuit*

The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and shall be supported by current or qualified past studies. The analysis shall be used to determine whether circuit breakers have the capability to interrupt the maximum short-circuit current the circuit breaker is expected to experience. [R2.3]

The System short-circuit model for the analysis shall be updated annually including planned generation and transmission facilities within NIPSCO and including planned generation and transmission facilities in adjoining areas within two busses of NIPSCO.

The maximum expected short-circuit current that a circuit breaker is expected to interrupt shall be determined by performing both three-phase (3Ø) and single line-to-ground (SLG) fault simulations in accordance with the IEEE standard C37-010-1999 and utilizing the calculation methodology of the ASPEN Oneliner™ Breaker Rating Module. The circuit breaker interrupting rating shall be based on its nameplate value and not derated based on circuit breaker reclosing operations.

Circuit breakers with interrupting duty of 100% or greater of the interrupting rating shall be considered an identified deficiency.

2.5 *Supplemental Performance Analysis*

2.5.1 Cascading

Cascading potential shall be evaluated by sequentially removing those facilities with steady-state loading in excess of 125% of their emergency rating and those generating units with steady-state terminal voltage below their specified voltage criteria. [R6]

2.5.2 Uncontrolled Islanding

Uncontrolled islanding potential shall be evaluated by review of identified cascading outages that result in load being isolated with generation from the interconnected system. [R6]

2.5.3 Voltage Stability

Voltage stability analysis shall be performed for the Near-Term and Long-Term Planning Horizons mentioned above. Voltage stability shall be evaluated through the application of the Fast Voltage Stability Index (FVSI) and Voltage Stability Index Le. Analysis shall be performed for N-0 and N-1 contingency conditions. A voltage stability index value of 1.0 or greater is an indication of voltage instability. [R6]

3 FACILITY CONNECTION, TRANSMISSION SERVICE REQUEST ASSESSMENTS, AND GENERATOR RETIREMENTS

Transmission Reliability Planning Tests are performed on Facility Connection projects, Transmission Service Requests (TSR's), and Generation Retirements to evaluate any Thermal or Voltage criteria violations caused by projects originated through PJM, MISO and NIPSCO processes on NIPSCO's transmission system.

3.1 *INDIVIDUAL CONTRIBUTION TEST AND CUMULATIVE IMPACT TEST (CIT)*

The Facility Connection Projects, TSR's, and Generation Retirements impacting NIPSCO's transmission shall be subject to two tests: the Individual Contribution Test and the Cumulative Impact Test.

The Facility Connections, TSR's, and Generation Retirements screened through the following two tests are studied for their impact on NIPSCO's transmission system. The RTEP and MTEP cases used by PJM and/or MISO will be used in the study process. Peak, off-peak, and high wind cases should be evaluated to determine worst-case impact. Mitigations will be determined for all thermal and/or voltage violations evaluated under NERC Contingency Categories P0, P1, P2, P5 and P7.

Individual Contribution Test:

The test is performed to identify individual Facility Connections, TSRs, and Generation Retirements affecting NIPSCO's transmission system. For a Facility Connection, TSR, or Generation Retirement to be considered to be impacting the NIPSCO transmission system, it should adhere to one of the two rules:

1. The contribution of the Distribution Factor of the Facility Connection, TSR, or Generation Retirement with magnitude of 3% or greater contributing to an overload on a NIPSCO facility.

2. The Contribution of a Facility Connection, TSR, or Generation Retirement on a NIPSCO facility is equal to or greater than 3% of the facility rating.

Cumulative Impact Test (CIT):

NIPSCO shall also perform a test to evaluate the cumulative impact of multiple Facility Connections, TSRs, and Generation Retirements when they are grouped together in the same study during the PJM and/or MISO process. The Facility Connections, TSRs, and Generation Retirements having a cumulative impact of at least 10% of the facility rating will be considered as impacting NIPSCO's transmission system. There is no minimum threshold to assign individual impact.

3.2 *ENERGY STORAGE OR HYBRID FACILITY INTERCONNECTIONS*

The maximum expected charging load for any storage or hybrid facility with grid charging capability interconnecting to NIPSCO's transmission system will be studied as a non-interruptible load in off-peak conditions according to the most recent NERC TPL-001-5 standard methodology using the most recent NIPSCO transmission planning criteria.

Stand-alone storage utilizing inverter-based machines shall have grid forming inverter control capability.

3.3 *POWER FACTOR DESIGN CRITERIA*

Interconnection Customer shall design the Generating Facility to be capable of 93% lead/lag power factor at nominal voltage and continuously rated real power output. Reactive resources necessary to meet this requirement shall be dynamic in nature. Power factor capability for synchronous machines shall be exhibited at the high-side winding bus of the generator step-up transformer. Power factor capability for inverter-based machines shall be exhibited at the high-side winding bus of the collector substation transformer. Reactive resource capability meeting this requirement shall be available throughout the full range of real power output.

TABLE 1. PLANNING AND EXTREME EVENTS

Category	Initial Condition	Event	Fault Type	Notes
P0	Normal System	None	N/A	Initial System Condition
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø	
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault	N/A	
		2. Bus Section Fault	SLG	
		3. Internal Breaker Fault (non-bus tie)	SLG	
		4. Internal Breaker Fault (Bus-tie Breaker)	SLG	
P3 Multiple Contingency	Loss of generator unit followed by System Adjustments	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø	
P4 Multiple Contingency (Fault plus Stuck Breaker)	Normal System	Loss of Multiple Elements Caused by a stuck Breaker (non-bus tie) attempting to clear a fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section 6. Loss of Multiple elements caused by a stuck Bus-tie Breaker attempting to clear a fault on the associated bus.	SLG	

Category	Initial Condition	Event	Fault Type	Notes
P5 Multiple Contingency	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus section	SLG	See TPL-001-5 footnote 13 for components under consideration for the purposes of this standard.
P6 Multiple Contingency	Loss of one of the following followed by System adjustments. Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device	Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device	3Ø	Curtailment of Firm Transmission Service is allowed as a System adjustment as identified in the column entitled 'Initial Condition'.
P7 Multiple Contingency	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure.	SLG	Excludes circuits that share a common structure for 1 mile or less.

Category	Initial Condition	Event	Fault Type	Notes
Extreme Event -Steady State 1	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	Steady State Only	
Extreme Event -Steady State 2	Normal	Local Area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits. b. Loss of all Transmission lines on a common Right-of-Way. c. Loss of a switching Station or Substation (loss of one voltage level plus transformers) d. Loss of all generating Units a generating Station e. Loss of a large Load or major Load Center	Steady State Only	
Extreme Event -Steady State 3	Normal System	Wide area events affecting the transmission System based on System Topology such as: a. Loss of two generating Stations. b. Other events based upon operating experience that may result in wide area disturbances.	Steady State Only	

Category	Initial Condition	Event	Fault Type	Notes
Extreme Event -Stability 1	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	Stability Only -3Ø	
Extreme Event - Stability 2	Normal System	Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker or a relay failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission Circuit with stuck breaker or a relay failure resulting in Delayed Fault Clearing. c. 3Ø fault on Transformer with stuck breaker or a relay failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker or a relay failure resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault f. Other events based upon operating experience, such as consideration of initiating evens that experience suggests may result in wide area disturbances.		