In addition, projects that originate through local Transmission Owner planning will be posted on the PJM web site. This site will include all currently planned transmission owner RTEP projects (including both newly planned Supplemental RTEP projects and Transmission Owner Initiated projects from past RTEP cycles that are yet to be placed in-service.) This site will provide tracking information about the status of listed projects and planned in-service dates. It will also include information regarding criteria, assumptions and availability of study cases related to local planning.

1.3 Planning Assumptions and Model Development

1.3.1 Reliability Planning

PJM’s planning analyses are based on a consistent set of fundamental assumptions regarding load, generation and transmission built into power flow models. Load assumptions are based on the annual PJM entity load forecast independently developed by PJM (found at http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-development-process.aspx.) This forecast includes the basis for all load level assumptions for planning analyses throughout the 15 year planning horizon. Generation and transmission planning assumptions are embodied in the base case power flow models developed annually by PJM and derived from the Eastern Reliability Assessment Group processes and procedures pursuant to NERC standard MOD-032. As necessary, PJM updates those models with the most recent data available for its own regional studies. All PJM base power flow and related information are available pursuant to applicable Critical Energy Infrastructure Information, Non-Disclosure and OATT-related requirements (accessible via http://www.pjm.com/planning/rtep-development/powerflow-cases.aspx or by contacting the PJM Planning Committee contacts.) Each type of RTEP analysis (e.g., load deliverability, generator deliverability etc.) encompasses its own methodological assumptions as further described throughout the rest of this Manual. Additional details regarding the reliability planning criteria, assumptions, and methods can be found in following sections and this manual’s Attachments.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

1.3.2 Market Efficiency Planning

PJM will perform a market efficiency analysis each year, following the completion of the near-term reliability plan for the region. PJM’s market efficiency planning analyses will utilize many of the same starting assumptions applicable to the reliability planning phase of the RTEP development. In addition, key market efficiency input assumptions, used in the projection of future market inefficiencies; include load and energy forecasts for each PJM zone, fuel costs and emissions costs, expected levels of potential new generation and generation retirements and expected levels of demand response. PJM will input its study assumptions into a commercially available market simulation data model that is available to all stakeholders. The data model contains a detailed representation of the Eastern Interconnection power system generation, transmission and load. In addition, the market efficiency analysis of the cost/benefit of potential market efficiency upgrades will also include the discount rate and annual revenue requirement rate. The discount rate is used to determine the present value of the enhancements’ annual benefits and annual cost. The
flow to the post-contingency power flow. The post-contingency power flow is solved with generators holding a local generator bus voltage to a pre-contingency level consistent with specific Transmission Owner specifications. In most instances this is the pre-contingency generator bus voltage. Additionally, all phase shifters, transformer taps, switched shunts, and DC lines are locked for the post-contingency solution. SVC’s are allowed to regulate and fast switched capacitors are enabled.

The voltage magnitude criteria is examined for the same contingency set by allowing transformer taps, switched shunts and SVC’s to regulate, locking phase shifters and allowing generators to hold steady state voltage criteria (generally an agreed upon voltage on the high voltage bus at the generator location.)

In all instances, specific Transmission Owner voltage criteria are observed. All violations are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

Post-Contingency voltage analysis shall also include the impact of tripping generators where the simulated generator bus voltages or the high side of the generation step up (GSU) transformer are less than known or assumed minimum generator steady state of ride through voltage limitations. All violations will be reported and tentative solutions will be developed. The results of these studies will be reviewed through the TEAC.

2.3.8 NERC P3 and P6 “N-1-1” Analysis

**Purpose:**

N-1-1 studies are conducted as part of the annual RTEP to determine if all monitored facilities can be operated:

- Within normal thermal and voltage limits after N-1 (single) contingency assuming re-dispatch and system adjustments, and

- Within the applicable emergency thermal ratings and voltage limits after an additional single contingency (N-1-1) condition.

All violations of the applicable thermal ratings are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

**Model:**

Annually, the N-1-1 study is conducted on a 50/50 non-diversified summer peak case. The case building details are defined in Attachment C (C7 3.0 Step 1: Develop Base Case). Non-firm Merchant Transmission withdrawals can be removed. All BES facilities in PJM and ties to PJM will be monitored. Areas of the system that become radial post-contingency will be excluded from monitoring, with the following exceptions:

- If the radial system contains greater than 300 MW of load, or

- Specific local TO Planning Criteria require that it be monitored.

**Contingencies considered:**
All BES single contingencies as defined in NERC P3 and P6 as well as lower voltage facilities that are monitored by PJM Operations will be included in the assessment. Non-BES contingencies, defined by Transmission Owners, need to be included to check for greater than 300 MW load loss. Non-BES facilities that are included in the assessment will also have corresponding contingencies defined.

AC Solution Options in the PSS/E program:

- For the first single contingency (N-1 Condition) and to ensure the system remains within emergency thermal ratings
  - Transformer tap adjustment enabled
  - Switched shunt adjustment enabled
- After the first single contingency (N-1 Condition) and to return the system back within normal thermal ratings
  - Phase shifter adjustment enabled
  - System re-dispatched
  - Topology changes implemented
- For the second single contingency (N-1-1 Condition) – Voltage Drop Test (if applicable)
  - Transformer tap adjustment disabled
  - Phase shifters locked to control angle, not flow
  - Switched shunt adjustment disabled except for fast switched capacitors
  - Generators are set to regulate their terminal bus
  - SVC’s are allowed to regulate
  - Automatic shunt adjustment disabled
- For the second single contingency (N-1-1 Condition) – Thermal and Voltage Magnitude Test
  - Transformer tap adjustment enabled
  - Phase shifters locked to control angle, not flow
  - Switched shunt adjustment enabled
  - Automatic shunt adjustment enabled
modeled reflects generation by fuel class that historically operates during the light load demand level.

The starting point power flow is the same power flow case set up for the baseline analysis, with adjustment to the model for the light load demand level, interchange, and accompanying generation dispatch. The PJM portion of the model is adjusted as well as areas surrounding PJM that impact loadings on facilities in PJM. Interchange levels for the various PJM zones will reflect a statistical average of typical previous years interchange values for off-peak hours. Load level, interchange, and generation dispatch for non-PJM areas impacting PJM facilities are based on statistical averages for previous off-peak periods. Thus the same baseline network model and criteria apply. The flow gates ultimately used in the light load reliability analysis are determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. The contingencies used for light load reliability analysis will include NERC TPL P1, P2, P4, P5 and P7. NERC TPL P0, normal system conditions will also be studied. All BES facilities and all non-BES facilities in the PJM real-time congestion management control facility list are monitored. The same single contingency power flow solution techniques also apply. Details of the light load reliability analysis procedure, including methods of creating the study dispatch, can be found in Attachment D.2. The resulting system enhancements from all Light Load reliability analysis are expected to be in-service prior to November 1 of the Delivery Year under study.

2.3.12 Spare Equipment Strategy Review

PJM will annually evaluate the spare equipment strategy that could result in the unavailability of major transmission equipment that has a lead time of one year or more (such as a transformer) and assess the impact of this possible unavailability on system performance using NERC category P0, P1 and P2 contingency categories identified in Table 1 of NERC TPL-001-4. This assessment will consider the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

2.3.13 Winter Peak Reliability Analysis

The winter peak reliability analysis ensures that the Transmission System is capable of delivering the system generating capacity at winter peak. The PJM 50/50 winter peak demand level was chosen as being representative of a typical winter peak condition. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the winter peak demand level.

The starting point power flow is the same power flow case set that is used for the baseline analysis, with adjustments to the model for the winter peak demand level, winter peak load profile, winter ratings, interchange, and accompanying generation dispatch. The PJM portion of the model is adjusted, and the MMWG winter model is used for areas surrounding PJM. Interchange levels for the various PJM zones will reflect all yearly long term firm (LTF) transmission service, except MAAC which will reflect the historical average. Load level, interchange, and generation dispatch for non-PJM areas impacting PJM facilities are based on statistical averages for previous winter peak periods. Thus the same baseline network model and criteria apply. The flow gates ultimately used in the winter peak reliability analysis are determined by running all applicable contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all NERC BES facilities. The
contingencies used for winter peak reliability analysis will include NERC TPL category P1, P2, P3, P4, P5, P6, and P7. NERC TPL Category P0, normal system conditions will also be studied. All BES facilities and all non-BES facilities in the PJM real-time congestion management control facility list are monitored. The same single contingency power flow solution techniques used in other baseline reliability tests also apply. Details of the winter peak reliability analysis procedure, including methods of creating the study dispatch, can be found in Attachment D.3. The resulting system enhancements from all Winter Peak reliability analysis are expected to be in-service prior to December 1 of the Delivery Year under study (For example, 2021 Winter Peak studies December of 2021 through February of 2022, System enhancements identified in this study are expected to be in-service prior to December 1, 2021).

2.3.14 Baseline Stability Analysis

PJM ensures generator and system stability during its interconnection studies for each new generator. In addition, PJM annually performs stability analysis for approximately one third of the existing generators on the system. Analysis is performed on the RTEP baseline stability cases. These analyses ensure the system is transiently stable and that all system oscillations display positive damping with damping ratio consistent with section G.2.2. Generator stability studies are performed for critical system conditions, which include light load and peak load for three phase faults with normal clearing plus single line to ground faults with delayed clearing. Also, specific Transmission Owner designated faults are examined for plants on their respective systems.

Finally, PJM will initiate special stability studies on an as needed basis. The trigger for such special studies commonly includes but is not limited to conditions arising from operational performance reviews or major equipment outages.

2.3.15 Maximum Credible Disturbance Review

The maximum credible disturbance review identifies extreme events, as defined in Table 1 of NERC Standard TPL-001-4, and assess their impact on system reliability. If the initial analysis shows cascading caused by the occurrence of extreme events, PJM will perform an evaluation of possible action designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s). This can include a stability analysis of the area and an evaluation of possible actions to reduce the likelihood of the event or mitigate the consequences and impacts on the system.

PJM will also assess the impact of extreme events using stability analysis. Extreme events contained in Table 1 of NERC TPL-001-4 that produce more severe impacts shall be identified and a list created of those events will be maintained and distributed to the appropriate entities. The rationale for those contingencies selected for evaluation shall be available as supporting information. If the initial analysis shows cascading by the occurrence of extreme events, PJM will perform an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s).

2.3.16 Long Term Reliability Review

The PJM RTEP reliability review process examines the longer term planning horizon, which spans the current year plus 6 through the current year plus 15, using a 24-month reliability planning cycle. At the beginning of the first year of the cycle, a 5-year out base case, a long-
C.7.2 Study Objectives

The goal of the PJM Generator Deliverability study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM. Any generators requesting interconnection to PJM must be “deliverable” in order to be a PJM installed capacity resource.

C.7.3 General Procedures and Assumptions

Step 1: Develop Base case

The RTEP base case is developed for a reference year 5 years in the future. All RTEP identified system upgrades and Supplemental RTEP Projects are included in the system model. Load is modeled at a non-diversified forecasted 50/50 summer peak load level. All approved firm interchange is included with roll-over rights. Generation and Merchant Transmission projects that have proceeded at least through the execution of the Facility Study Agreement stage of the interconnection process are considered in the model along with any associated network upgrades. The starting point dispatch is developed as explained in the next step. PJM uses a uniform reduction of generation in place of discrete forced outages for this test due to the significant bias any one specific outage pattern can have on the final overload results.

Step 2: Establish initial RTEP dispatch for unit under study

Place all in-service capacity resources (those that have procured capacity delivery rights) on-line at a generation value equal to their installed capacity x (1 – PJM average EEFORd). Wind units with capacity delivery rights are derated to their granted capacity rights (either 13% beginning with the “U” queue or 20% for prior queues) representing the combined effects of wind variation and outage characteristics. The target generation value is the projected load + losses + firm interchange. (See addendum 1 for treatment of transmission withdrawal and injection rights). If all in-service capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all in-service capacity resources should be uniformly reduced to meet the target generation value. If all in-service capacity resources de-rated by the PJM EEFORd is less than the target generation value, then place all capacity resources with an executed Interconnection Service Agreement (ISA) on-line at a generation value equal to the installed capacity x (1 – PJM average EEFORd). If all in-service and ISA capacity resources are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value. If all in-service and ISA capacity resources de-rated by the PJM EEFORd is less than the target generation value, then place all capacity resources with an executed Facility Study Agreement on-line at a generation value equal to the installed capacity x (1 – PJM average EEFORd). If all in-service, ISA and Facility Study capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value.

All resource requests in the study queue ahead of the unit under study are set at 0 MW but available to be turned on. The resource request under study is also set at 0 MW but available to be turned on. Resource requests queued after the unit under study are not modeled. The loading on each transmission line that results from this dispatch and the application of a contingency is the base loading of the facility. (See Addendum 2 for treatment of Common Mode Outage Procedures).
Step 3: Determine potential overloads

PJM uses a linear (DC) power flow program to analyze each facility for which PJM is responsible to determine whether any contingencies can overload the facility (including comprehensive analysis of single, towerline, bus, and stuck breaker contingencies). These results are utilized to determine which flowgates will be used in the generator deliverability analysis, i.e., the program examines each PJM flowgate (contingency / monitored element pair) on the entire PJM footprint. The procedure below explains conceptually how the program works; following the procedure below would yield the same results as the program. The procedure uses a load flow set up according to step 2.

Determine the distribution factor for each generator on each flowgate. The distribution factor for a particular generator is referenced to the PJM online generation. For each flowgate, multiply the distribution factor of each generator by the offline portion of the generator to obtain the MW impact the generator would have on a particular flowgate if it were ramped from its output in the initial load flow to its full output. This result will be referred to the ramping impact of a particular generator on a particular flowgate. For all flowgates determine the cumulative ramping impact of generators with greater than a 1% distribution factor. The total amount of ramped generation is capped to limit the number of potential overloads to a reasonable number of the worst impacts. A typical cap for the total ramping is 10,000 MW but the actual value can vary to establish a reasonable scope for the potential overloads. For each flowgate, add the cumulative ramping impact to the initial DC loading. If the resulting DC loading is greater than the flowgate rating, then this flowgate is a potential overload.

Step 4: Determine 80/20 DC loading

The number of generators having greater than a 1% distribution factor in Step 2 is often large enough that having them all simultaneously outputting their full installed capacity would be extremely improbable. As a result, in this step the number of generators contributing to the cumulative ramping impact on a flowgate is further restricted in the following manner.

Units modeled in the power flow with greater than a 5% distribution factor (or 10% distribution factor for flowgates whose monitored element’s lowest terminal voltage level is equal to or greater than 500 kV) that contribute to the cumulative ramping impact are ranked according to their distribution factor on a potentially overloaded flowgate. The availability \((1 − \text{EEFORd})\) of the unit with the highest distribution factor is then multiplied by the availability of the unit with the second highest distribution factor and so on until the expected availability of the selected units is as close to but not less than 20%. This resulting “80/20” cumulative ramping impact is then added to the initial DC loading on the flowgate. This resulting loading is the 80/20 DC loading and the generators chosen to contribute to the cumulative ramping impact are the 80/20 generators.

Step 5: Determine Facility Loading Adder

This Step 5 addresses off-line generators which are not included in the 80/20 list. Existing generators that do not have capacity delivery rights and active queued generators that are not yet in commercial operation (or do not yet have a signed ISA) are offline but available to be turned on. The ramping impact of this set of generators determines the Facility Loading Adder. First, for their ramping impact to be considered, off-line generators must pass the impact threshold of at least a 5% DFAX (10% for flowgates with monitored elements having...
the lowest terminal voltage 500 kV and above) on a flowgate or with an impact (DFAX times a generator's full energy output rating) greater than 5% of the flowgate’s rating.

The ramping impact of offline generators is determined according to their classification as: (1) active queued generators with signed ISA’s, or (2) active queued generators without signed ISA’s. Category (1) generators are allowed to aggravate or backoff overloaded flowgates. Category (2) generators are considered only if they aggravate overloaded flowgates (active queued generators without signed ISAs are not allowed to backoff overloads.)

For each potential flowgate, an approximated CETO will be calculated by finding a receiving end area. The receiving end area will include:

- Load buses with a positive impact on flowgate loading
- Generators with negative impact on flowgate loading

The estimated CETO will be calculated using the following function:

\[
\text{Estimated CETO} = 1.08 \times (\text{Bus Loads} + \text{Losses} - \text{Diversity} - \text{Demand Response}) - (1 - 1 \times \text{Avg. EEFORD}) \times \text{ICAP} + \text{Largest Unit}
\]

Each receiving end area will be assigned a portion of the PJM Capacity Benefit Margin (CBM) based the receiving end area’s share of the PJM load. CBM will be used to offset generators that contribute to the Facility Loading Adder when the import level for a receiving end area becomes greater than:

\[
(\text{receiving end area estimated CETO} - \text{receiving end area CBM allocation})
\]

To ensure that new generators within small clusters of the electrically closest generation to a flowgate will not be offset by the delivery cap, an exception to the CBM offset will be made. Generators which contribute to the Facility Loading Adder and have distribution factors that fall outside of two standard deviations of the mean of all PJM generator distribution factors will be available to contribute to the Facility Loading Adder. The amount of generation change from the initial load flow due to changes in 80/20 and Facility Loading Adder generation shall not be any more than the online installed capacity exclusive of the 80/20 generators \( \times \) PJM average EEFord. This rule is enforced by curtailing generators that contribute to the Facility Loading Adder. In order to always maintain a critical system condition for this deliverability test, the 80/20 or 50/50 generation, as applicable, will not be curtailed to enforce this rule.

The ramping impact of active queued generators without signed ISA’s considers the commercial probability of queued generators at the feasibility study stage of the interconnection process. For generators at the feasibility study stage of the interconnection process, the output of the generator is multiplied by the historic commercial probability of a generator at the impact study stage of the interconnection process. To be conservative, the values developed during the feasibility study stage are then multiplied by 150% to determine the ramping impact of generation at the feasibility study of the interconnection process. The entire requested capacity of queued generation is used to determine the ramping impact of generation that has signed an impact study or facility study agreement.

The summation of 85% (100% for a Merchant Transmission project) of the ramping impact on a flowgate of each off-line resource that meets the above conditions is calculated. The resulting impact defines the Facility Loading Adder. The Facility Loading Adder is added to the base loading and the 80/20 DC loading to obtain the final DC loading on the facility.
Attachment D-3:  PJM Reliability Planning Criteria Methods

D-3.1 Winter Peak Reliability Analysis

The winter peak reliability analysis tests the ability of an electrical area to export generation resources to the remainder of PJM during winter peak conditions. The export generation is selected by using the historical mix of generation that operates at the winter peak level. This test is applied to ensure that generation capability, including renewable generation capability that typically operates at winter peak such as wind, as well as pumped hydro are not "bottled" from a reliability perspective.

The winter peak reliability analysis, from the perspective of individual generator resources, ensures that, under winter peak system conditions, their ability to provide energy to the system has a probability of not being limited by the typical dispatch of other generation resources that operate at that demand level, including resources in neighboring systems. The Generator Deliverability Test and Common Mode Outage procedure have a similar objective at the summer peak forecast load. While deliverability under all possible system conditions is not in the purview of the RTEP, analyzing the system performance under this wide range of forecasted demand levels improves overall deliverability of generating resources. Consideration will be given to the capacity factor by fuel class during this period, as described in Table 1. This test does not guarantee that a given resource will be able to deliver energy at the winter peak condition. Rather, the purpose is to demonstrate that typical winter peak generating capabilities in any electrical area can be run simultaneously, at winter peak, and that the excess energy above demand in that electrical area can be exported to the remainder of PJM. In short, the test ensures that bottled capability conditions will not exist at winter peak, limiting the availability and usefulness of a range of resources available to system operators, including renewable resources. In actual non-emergency operating conditions, the economic dispatch serves load.

D-3.2 Winter Peak Reliability Analysis Procedure

1.0 Introduction

To maintain reliability and operational flexibility during the winter peak period, resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM. PJM utilizes a Winter Peak Reliability Analysis procedure to study the system performance during typical winter peak conditions. This document provides the procedure for Winter Peak Reliability Analysis.

2.0 Study Objectives

The goal of the PJM Winter Peak Reliability Analysis study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM during winter peak conditions. Generators requesting interconnection to PJM must pass this test in order to become a PJM capacity or energy resource.

Additionally, the PJM Winter Peak Reliability Analysis will be used to ensure thermal and voltage adequacy based on normal (applicable to system normal conditions prior to contingencies) and emergency (applicable after the occurrence of a contingency)
thermal ratings specific to the Transmission Owner facilities being examined during winter peak conditions.

3.0 General Procedures and Assumptions for Winter Peak Reliability Analysis

Step 1: Develop Base case

The RTEP base case is developed for a reference year 5 years in the future. All RTEP identified system upgrades and Supplemental RTEP Projects are included in the system model. PJM load is modeled at a non-diversified forecasted 50/50 winter peak load level per the latest applicable PJM load forecast. In coordination with individual TOs, PJM will select and apply a Transmission Facility temperature degree ratings set (50F, 41F or 32F as defined by the ratings submitted to PJM Operations in accordance with FAC-008) as appropriate. PJM will apply the ratings set on an individual TO basis. Target PJM RTO area interchange that reflects all yearly long term firm (LTF) transmission service will be maintained. Generation and Merchant Transmission projects that have proceeded at least through the execution of the Facility Study Agreement stage of the interconnection process are considered in the model along with any associated network upgrades. The starting point dispatch is developed as explained in the next step.

Step 2: Establish initial RTEP dispatch for unit under study

Existing PJM Resources: Place all in-service nuclear resources on-line at a generation value equal to their installed capacity. Wind units are derated in the initial dispatch to 33% of their nameplate capability. Coal units are initially derated consistent with Table 1. Queued Units in the PJM queue that have an ISA will be placed on-line consistent with Table 1. The target generation value for each Transmission Owner (TO) zone in the model is dispatched at a magnitude to meet the projected load + losses + PJM RTO interchange. In addition, for the PJM MAAC zone, the average historical interchange for the winter peak period, as calculated by PJM is calculated and applied to that zone. If necessary, generation resources in each TO zone are then uniformly de-rated until the target generation value is met.

The following applies to all queued resources in PJM and neighboring systems. Model all non-ISA queued generation offline. All ISA queued generation is modeled online. If selected by the test procedure, PJM queued resources will have the potential to be dispatched to 100%.

For queued interconnection studies, all queued resources in the study queue ahead of the unit under study are set at 0 MW but available to be turned on per the Generator Deliverability procedure and Common Mode Outage test procedure. The resource request under study is also set at 0 MW but available to be turned on. Resource requests queued after the unit under study are not modeled. The loading on each transmission line that results from this dispatch and the application of a contingency is the base loading of the facility. (See Addendum 2 for treatment of Common Mode Outage Procedures).
Table 3 – Winter Peak Base Case Initial Target Dispatch

<table>
<thead>
<tr>
<th>Network Model</th>
<th>Current year + 5 base case</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Load Model</strong></td>
<td>50/50 Winter Peak with the bus by bus load profile set by the local Transmission Owner</td>
</tr>
</tbody>
</table>
| **Capacity Factor for Base Generation Dispatch for PJM Resources (Online in Base Case)** | **Solar** – 5%  
Wind – 33%  
Water – 38%  
Nuclear – 98%  
Coal < 500 MW – 51%  
Coal >= 500 MW – 73%  
Landfill Gas – 46%  
Natural Gas – 25%  
Other Biomass Gas – 111%  
Oil (Distillate Fuel)– 1%  
Oil (Black Liquor)– 74%  
Oil (Kerosene)– 0%  
Oil (Residual Fuel)– 2%  
Municipal Solid Waste – 79%  
Wood Waste – 66%  
Waste Coal – 75%  
Petroleum Coke – 75%  
Other Solid – 19% |
| **Interchange Values**               | Yearly long term firm (LTF) transmission service (except MAAC which will use historical averages) |
| **Contingencies**                   | NERC Category P0, P1, P2, P3, P4, P5, P6, and P7            |
| **Monitored Facilities**            | All PJM market monitored facilities                          |

**Step 3: Determine potential overloads**

The method to determine potential overloads is similar to the methods used for the generator deliverability test. Also, the Common Mode Outage procedure is applied to include the effects NERC Category P2, P4, P5, and P7 events such as bus faults, faulted breakers, and double circuit towerline outages.
Step 4: Determine 80/20 DC loading

This portion of the test is similar to the generator deliverability procedure except the ramping limits listed in Table 2 are enforced.

Table 2 – Winter Peak Study Generation Ramping Limits

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Ramping Limits (% of Pmax)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar</td>
<td>10%</td>
</tr>
<tr>
<td>Wind</td>
<td>80%</td>
</tr>
<tr>
<td>All other resources</td>
<td>100%</td>
</tr>
</tbody>
</table>

Step 5: Determine Facility Loading Adder

This portion of the test is similar to the generator deliverability procedure except ramping limits listed in Table 2 are enforced.

Step 6: Determine Final Flowgate Loading

This portion of the test is similar to the generator deliverability procedure except ramping limits in Table 2 are enforced.

4.0 General Procedures and Assumptions for Load Deliverability (NERC P1) Test

The PJM system will be analyzed using the same procedure as applied in section 2.3.9 Load Deliverability Analysis, however the winter case as described previously in this section will be used as the study case.

5.0 General Procedures and Assumptions for Normal System (NERC P0) and N-1 (NERC P1) Events

The PJM system will be analyzed using the same procedure as applied in section 2.3.6 Baseline Thermal Analysis and section 2.3.7 Baseline Voltage Analysis and monitored for thermal and voltage limits, however the winter case as described previously in this section will be used as the study case.

6.0 General Procedures and Assumptions for “N-1-1” (NERC P3 and P6) Events

The PJM system will be analyzed using the same procedure as applied in section 2.3.8 NERC Category P3 and P6 “N-1-1” Analysis, however the winter case as described previously in this section will be used as the study case.

7.0 Consideration of Gas Pipeline Contingencies

PJM will maintain and apply a gas pipeline contingency analysis. The gas pipeline contingency set will include gas pipeline contingencies due to the failure of a gas pipeline or a compressor station. The gas pipeline contingency list will be reviewed periodically to validate its accuracy. In addition to the gas pipeline contingencies, gas temperature threshold contingencies will be evaluated. At a pre-determined temperature threshold, assume that non-firm customers (i.e. non-heating demand and 100% of natural gas generation customers in that zone) will be interrupted.
H.1 Power System Modeling Data

Accurate power system modeling data is a key component of quality power system analysis. PJM System Planning uses a variety of models and analytical techniques to create and maintain the simulation models used for the RTEP studies. The intended use of this Attachment is to supplement existing documentation by PJM and other entities that specify accurate modeling data requirements. PJM will continue to follow the data guidelines and standards set forth by NERC as part of the MOD standards and the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Procedural Manual.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

H.1.1 Load Flow Analysis Models

Base case creation is a collaborative process between PJM and its members. From a technical standpoint PJM follows the guidelines set forth in the ERAG MMWG Procedural Manual. In the following sections, the logistics and transfer of information between PJM and its members are detailed.

Annual Updates

In the late third quarter of each year, PJM will ask Transmission Owners to review and update the base case and project files in Model On Demand. The base case updates will include committing case corrections along with in service projects with as built data to the base case. Project files will be updated for status, scope change, and in service date change. PJM will then use Model On Demand to build trial 1 cases for +5 year Summer, Light Load, and Winter which will be sent to Transmission Owners for review. Transmission Owners will provide:

- Network updates to the model that will advance the case to represent a current year + 5 base case with respect to the 1st Quarter of the following year. This update should be reviewed for correctness and compatibility with the final version of the base case under development
- Complete NERC P1, P2, P3, P4, P5, P6 and P7 contingency file updates that correspond to the updated network model (Include any contingencies which may not change the powerflow model, but change contingency definitions)
- Maximum credible disturbance (NERC TPL-001-4 Table 1 Extreme Events) contingencies
- Any other significant changes such as new load or block load additions
- Support, if necessary, for the development of network models for additional years and demand levels for both near term (years 1 through 5) and longer term (beyond 5 years) analyses.
Interim Updates and Communication of Significant Modeling Updates

In the event that PJM makes a major update to the RTEP analysis models outside of the annual model update window, PJM will notify PJM Transmission Owners of the modeling update through the Transmission Expansion Advisory Committee (TEAC) meetings. Also, PJM will notify neighboring entities that PJM determines may be impacted. In addition to the notification, PJM will make the updated affected models available upon request.

Generation Owner Requirements:

- Specific information regarding generator capability per MOD-032

H.1.2 Load Flow Modeling Requirements

In addition to the guidelines set forth by NERC and the ERAG MMWG procedural manual, PJM uses several specific procedures in establishing the base case so that it represents the best starting point for the annual RTEP analysis.

Generator step-up transformers

Generator models should represent the physical plant lay-out to the extent possible, explicitly modeling generator step-up transformers (GSUs) and Station Service loads (aka Auxiliary loads). This applies to units above 20 MW and connected to the BES system, consistent with BES requirements. Plants consisting of multiple units aggregating to 75 MW or more also require explicit representation of GSUs and station service loads.

Modeling of Outages

Known outages of Generation or Transmission Facilities with a duration of at least six months will be included under those system peak or off-peak conditions in the appropriate base case model. PJM may not model these outages in every case that is used for RTEP analysis, but will select appropriate scenarios to assess these changes. Additionally, PJM will analyze a subset of maintenance outages submitted through eDart under those system peak or off-peak conditions.

Interchange

The PJM net interchange in the summer peak case is determined by the firm interchanges that are represented in the PJM OASIS system. That interchange, in the summer peak case, shall be represented as 100% of the confirmed firm import and export reservations. Reservations associated with individual generation units, or group of units at a facility, shall be used in representing the interchange. The interchange in light load cases follows the light load criteria as defined in the Light Load Reliability Analysis in section 2.3.10 of this manual.

Generator Reactive Capability

Annually, PJM updates the model for the generator reactive capability (GCAP) of each generator based on data used by PJM Operations, which includes default limits obtained from the most up to date d-curves as well as data provided by the Generator Owners.