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 website 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-dev-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 standards MOD-010-0, -011-0, and -012-0 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
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

PJM NERC P3 and P6 “N-1-1” Methodology:

**Thermal Test Methodology:**

The PJM NERC P3 and P6 “N-1-1” Analysis will test the outage of every single contingency (N-1 condition)

The first step of the test is to ensure that post-contingency loadings of all facilities shall be within their emergency thermal ratings immediately following the first N-1 contingency.

The second step of the test is to ensure that post contingency loadings of all facilities shall be within their normal thermal ratings after the first N-1 contingency and subsequent re-dispatch and system adjustments. Allowable system adjustments include generation dispatch, phase shifter adjustment, system reconfiguration and load throwover.

The third step is to take the second N-1-1 contingency. Every second N-1-1 contingency is taken on every optimized N-1 scenario case to model the N-1-1 condition. After the second N-1-1 contingency, the thermal loading of any monitored facility that is above the applicable emergency thermal rating (long-term or short-term) is considered a reliability criteria violation and a mitigation plan will be needed.

**Voltage Drop Test Methodology:**

The N-1-1 Voltage Drop Test procedure follows a similar method as the thermal test method, except all monitored facilities are monitored for the emergency voltage drop limit after the second contingency (N-1-1 condition.) The calculation of voltage drop is defined in section 2.3.7.

**Voltage Magnitude Test:**

The N-1-1 Voltage Magnitude Test procedure follows a similar method as the thermal test method, except all monitored facilities are monitored for the emergency low limit after the second contingency (N-1-1 condition.)
contingency power flow solution techniques also apply. Details of the generation deliverability procedure can be found in Attachment C.

One additional step is applied after generation deliverability is ensured consistent with the load deliverability tests. The additional step is required by system reliability criteria that call for adequate and secure transmission during certain NERC P2, P3, P4, P5 and P6 common mode outages. The procedure mirrors the generator deliverability procedure with somewhat lower deliverability requirements consistent with the increased severity of the contingencies.

The details of the generator deliverability procedure including methods of creating the study dispatch can be found in Attachment C.

2.3.11 Light Load Reliability Analysis

The light load reliability analysis ensures that the Transmission System is capable of delivering the system generating capacity at light load. The 50% of 50/50 summer peak demand level was chosen as being representative of an average light load 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 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. (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), 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 flowgates 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
C.7 Generator Deliverability Procedure

C.7.1 Introduction

To maintain reliability in a competitive capacity market, resources must contribute to the deliverability of the Control Area in two ways. First, energy must be deliverable, from the aggregate of resources available to the Control Area, to load in portions of the applicable PJM region experiencing a localized capacity emergency, or deficiency. PJM utilizes the CETO / CETL procedure to study this “deliverability of load”. Second, capacity resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM that are experiencing a capacity emergency. PJM utilizes a Generator Deliverability procedure to study the “deliverability of individual generation resources”. This document provides the procedure for Generator Deliverability.

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

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 highest/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 – 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 highest/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 on 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 × 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.
3.0 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. PJM load is modeled at 50% of a non-diversified forecasted 50/50 summer peak load level. System Interchanges will be determined by PJM through the use of data, including statistical averages based on historical data for off-peak load periods for typical previous years. 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 combination of uniform reduction of coal powered generation and discrete outages for this test.

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 40% 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 the projected load + losses + historical interchange for the light load period, as calculated by PJM. If necessary, coal resources in each TO zone are then uniformly de-rated or increased from the initial dispatch until the target generation value is met.

Existing MISO Resources: Model all existing wind generation in the MISO area online at a 100% capacity factor. Sink all MISO generation uniformly to maintain the target interchange. MISO generation dispatch utilized to serve MISO load will reflect a typical yearly statistical average for off-peak periods for interchange between MISO West, Central, and East.

Queued Resources in PJM and neighboring systems: Model all non-ISA queued generation offline. Model all ISA queued generation online. If selected by the test procedure, queued MISO wind resources will have the potential to be dispatched to 100% capacity factor. Similarly, if selected by the test procedure, queued PJM wind resources will have the potential to be dispatched to 80%.

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).
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 P2, P3, P4, P5, P6 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 – Light Load Study Generation Ramping Limits

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Ramping Limits (% of Pmax)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>100%</td>
</tr>
<tr>
<td>Wind</td>
<td>80%</td>
</tr>
<tr>
<td>Coal &gt;=500 MW</td>
<td>60%</td>
</tr>
<tr>
<td>Coal &lt; 500 MW</td>
<td>45%</td>
</tr>
<tr>
<td>All other resources</td>
<td>0% (not ramped)</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.
• 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.

• Verification that all baseline, network and supplemental upgrades are included in the updated case along with a written description of any case modifications.

• Notification of any changes to tie lines whether they are ties internal to PJM or to external companies.

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.10 and MOD.12MOD-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.