PJM Market Efficiency Modeling Practices

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Contents

Summary: This document provides PJM stakeholders with a summary of the PJM Market Efficiency Modeling Practices including the Market Efficiency Input Assumptions and Data Model. This document should only be used as a reference and PJM may utilize different practices at PJM's discretion within the governance of the PJM Tariff and Operating Agreement. PJM may update this document as appropriate at anytime.

1. Market Efficiency Analysis Overview

1.1 Purpose

PJM's Regional Transmission Expansion Plan (RTEP) Process includes a market efficiency analysis, the goal of which is to accomplish the following objectives:

1. Determine which reliability-based enhancements have economic benefit if accelerated.
2. Identify new transmission enhancements that may realize economic benefit.
3. Identify economic benefits associated with modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such enhancements, originally identified to resolve reliability criteria violations, may be designed in a more robust manner to provide economic benefits as well.

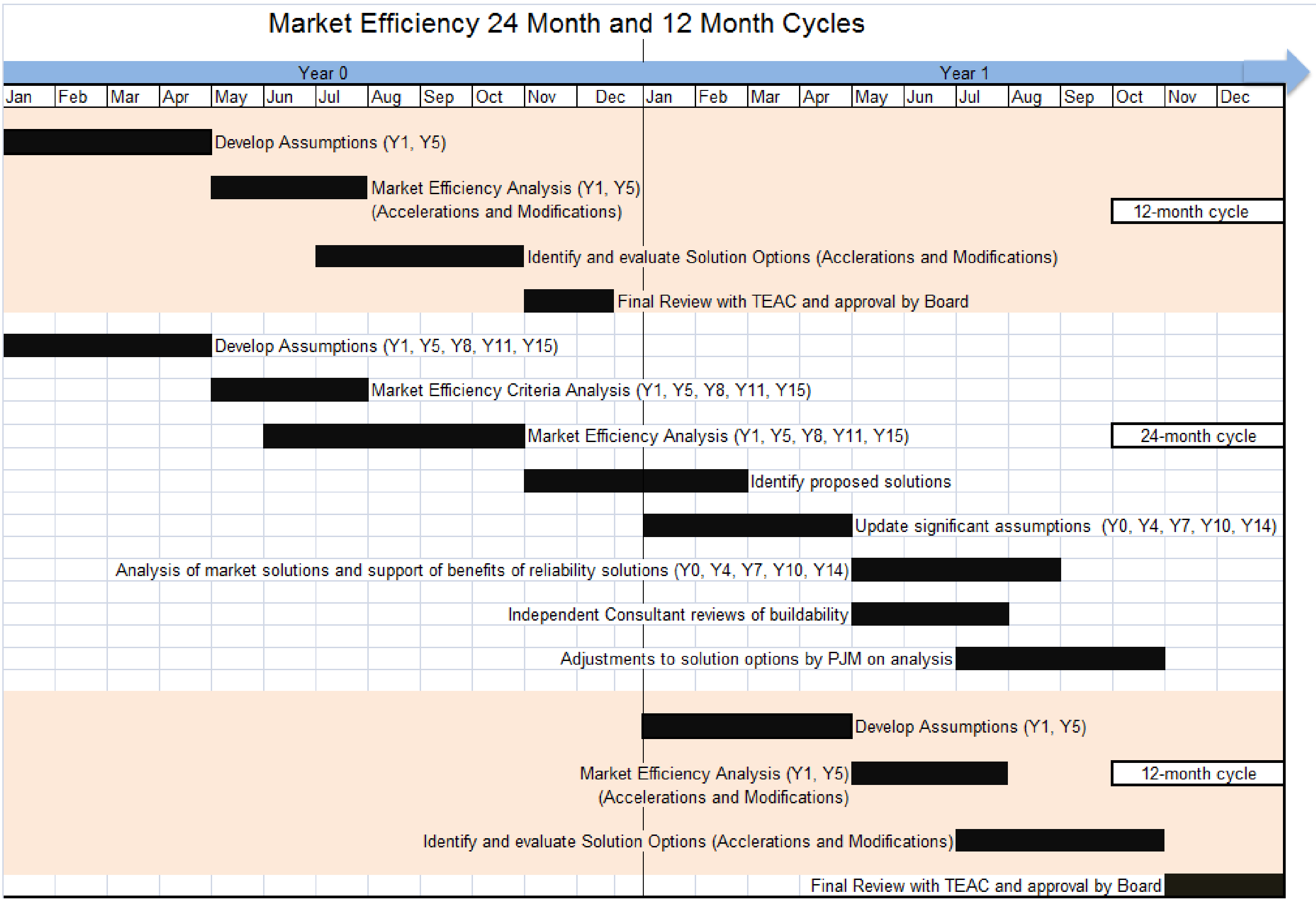
Economic benefits of proposed transmission projects can be created by mitigating congestion within production cost simulations of PJM's transmission and generation dispatch systems. The benefit metrics are determined by comparing future year simulation results of PJM's system, both without and with the proposed transmission enhancement. The set of metrics utilized and the methods involved with benefit determination are further described in Manual 14B Section 2.6 and Schedule 6 Section 1.5.7 of the PJM Operating Agreement.

Interaction between PJM staff and PJM membership concerning Market Efficiency Analysis is accomplished through the Transmission Expansion Advisory Committee (TEAC). It is within the TEAC charter that the committee will provide comments and recommendations concerning the assumptions, scope, and analysis of results to PJM staff and where appropriate to the PJM Board. The PJM Board will consider market efficiency study assumptions and approve proposed transmission projects and cost responsibility that is derived from a recommended project.

1.2 Timeline

Currently the Market Efficiency process approximates both a 12-month and a 24-month cycle that begins and ends at the end the year. The timeline for the Market Efficiency cycles is shown in Figure 1.

Figure 1: Market Efficiency Timeline



The 12-month cycle consists of a six month window for developing assumptions and case development. These assumptions will be reviewed with the TEAC. This 12-month cycle is utilized for analysis of modifications and accelerations to approved RTEP projects only. Projects evaluated during this 12-month cycle would need to be completed and reviewed with TEAC members for approval by the PJM Board by the end of the cycle.

The 24-month cycle consists of a six month window for developing assumptions and case development. These assumptions are the same assumptions utilized in the 12-month cycle. This 24-month cycle is utilized for analysis of new economic transmission upgrades for years 5 thru 15. The 24-month cycle consists of a four month proposal window as shown in the timeline. This long-term proposal window takes place concurrent with the long-term proposal window for reliability projects. After the completion of the proposal window, PJM will have eight months for analysis of all proposed projects. During these eight months, some input assumptions may be updated, the proposed projects will be evaluated for benefits and constructability, reliability projects will be evaluated for market benefits, and if necessary modification to proposed projects may occur. The final review with TEAC, recommendation to board, and board approval will be completed by the end of the cycle.

1.3 Tools

The primary application used in Market Efficiency Analysis is the PROMOD IV software tool contracted from ABB. PROMOD IV is fundamental electric market simulation software that incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, and market system operations to support economic transmission planning. PROMOD IV simulation engine is an hourly chronological dispatch algorithm that minimizes dispatch costs while simultaneously observing a wide variety of operating constraints, including generating unit characteristics, transmission limits, fuel and environmental considerations, transactions, and customer demand. The Promod IV data inputs, simulation methodologies, and outputs are described in detail at the link below:

http://new.abb.com/docs/librariesprovider139/default-document-library/promod-iv-technical-overview_br.pdf?sfvrsn=2

2.0 Market Efficiency Input Assumptions and Data Model

The Market Efficiency Input Assumptions are presented to PJM Members through the Transmission Expansion Advisory Committee (TEAC). The purpose of this is to both present and facilitate discussion of the high level economic drivers and physical characteristics of the PJM system used in the base case setup of the 15-year simulation period. Ultimately, the input assumptions are presented to the PJM board for information (usually at the June meeting). Market Efficiency Input Assumptions are only updated for significant changes during the second half of the 24-month cycle and projects proposed or developed as part of the Market Efficiency 24-month cycle will be analyzed with updated input assumptions. Significant assumptions may include but are not limited to large differences in load forecast, fuel assumptions, emission prices, financial assumptions, and new or retired large generators.

Key input assumptions include:

- Fuel prices
- Emission prices
- Annual PJM peak load and energy
- Quantity of demand response modeled
- Quantity of generation modeled and relationship to reserve margin
- Carrying charge rate and discount rate

The Market Efficiency data model is initially seeded with a base release of the PROMOD Simulation Ready Data NERC Database for the Eastern Interconnection. This will provide for a fully loaded PROMOD Database of the Eastern Interconnection setup with generation and load and a corresponding bus level transmission representation that can be run within PROMOD IV.

However the requirements of the Market Efficiency Process make modification of the initial case necessary for the following general reasons:

- To provide a more current view of PJM market fundamentals
- To provide an updated transmission model

The remainder of this section will discuss important considerations and recent methods for key areas of base case modification.

2.1 Area Structure

The area structure defines the hierarchy and reporting structure of the entities being modeled as part of the PROMOD database. It allows for creation of ownership, and linkages to other characteristics of these entities within the PROMOD IV simulation. The areas are generally hierarchically parented by regional entities which are in turn parented at the pool level.

Generally, in the PJM modeling, at the lowest level of the hierarchy, is the Transmission Owner (TO) zones that are necessary to report simulation results and which may have allocated cost responsibility in the Market Efficiency studies. Most the TO zones that are part of the area structure correspond to the TO zones that have forecasted load within the PJM Load Forecast. There are also several area structure TOs that do not serve retail load, but are merchant transmission owners that use part of the PJM transmission system and can be allocated costs of new transmission. The merchant transmission characteristics are defined by event file constraints within the PROMOD model. Additionally, a PJM area to capture external unit long-term firm import reservations is included in the model. See Figure 2 for the PROMOD PJM Area Structure.

Figure 2 - PJM Area Structure

Level 1	Level 2	Level 3	Level 4	Level 4	Entity Type
PJM Interconnection					Pool
	PJM MidAtlantic				Region
		PJM MidAtlantic - E			Sub-Region
				Atlantic Electric	TO Zone
				Delmarva Power & Light Company	TO Zone
				Jersey Central Power & Light Company	TO Zone
				PECO Energy Company	TO Zone
				Public Service Electric & Gas Company	TO Zone
				Rockland Electric Company	TO Zone
		PJM Mid-Atlantic - SW			Sub-Region
				Baltimore Gas & Electric Company	TO Zone
				Potomac Electric Power Company	TO Zone
		PJM Mid-Atlantic West			Sub-Region
			PJM MidAtlantic - East PA		Sub-Region
				Metropolitan Edison Company	TO Zone
				PPL Electric Utilities	TO Zone
			PJM MidAtlantic - West PA		Sub-Region
				Pennsylvania Electric Company	TO Zone
	PJM West				Region
				Allegheny Power	TO Zone
				American Electric Power	TO Zone
				Commonwealth Edison Co.	TO Zone
				Dayton Power & Light Co.	TO Zone
				Duke Energy Ohio/Kentucky	TO Zone
				Duquesne Light Company	TO Zone
				East Kentucky Power Coop.	TO Zone
				FirstEnergy ATSI	TO Zone
	PJM South				Region
				Virginia Power Company	TO Zone
	PJM Firm Reservations				LT Firm Use

2.2 Load Forecast Input Modeling and Derivation

The PJM Market Efficiency load model utilizes single pass loss logic. This logic includes input loads, which include zonal loss assumptions, and can be obtained from the PJM load forecast. The load data used in the market efficiency simulations are a combination of load data embedded in the annual PROMOD database (i.e. load shapes) and values representing the official PJM load forecast characteristics. PJM will incorporate the latest PJM load forecast into PROMOD. This process includes incorporating the monthly non-coincident peak and energy values by PJM transmission zone into the PROMOD model. These are provided in the monthly tables released as part of the PJM Load Forecast Report. These data items represent weather normalized unadjusted peak and energy values and include assumptions for energy efficiency (EE) and distributed solar. Note that model inputs are at a zonal level, to the extent that zonal load shapes create diversity patterns that differ from the forecasted diversity, the modeled PJM peak hour load may differ from the forecast.

Once the forecast values are incorporated into the PROMOD database, PJM will perform a number of bus level validations to ensure that load is properly assigned to the appropriate PROMOD areas. Based on available information at the time of developing the base case, the only adjustments to the load distribution represented within the power flow model is to verify that behind-the-meter and station loads are either removed from the model or not included in the area load distribution. There are also some large industrial loads within the Eastern Interconnect that have different load characteristics than typical scale-able load. To the degree that information is available on non-scale-able loads hourly patterns, they can be modeled in PROMOD as nonconforming. These validations and modifications are necessary to ensure that the appropriate loads are scaled according to the PJM Load Forecast and so that congestion is represented appropriately.

2.3 PJM Generation Modeling

Generation modeling within the Market Efficiency Analysis framework refers to the creation and verification of an expected resource plan for the PJM active footprint within the PROMOD IV simulations. This entails reviewing the characteristics, bus locations and timing of modeled supply resources over the entire fifteen year study period.

2.3.1 PJM Generation Modeling – Unit Specific Plan

The tasks necessary to create and verify the generation plan include the following:

- Identification of capacity and energy resources modeled within the current 5-year out RTEP load flow case
- Retirement of existing resources according to officially announced timetables
- Extension of existing resources in the absence of official retirement announcement
- Addition or modification of future unit specific resources based on queue processing and load flow representation
- Retirement of database future resources not meeting queue processing requirements
- Scaling of resource capacity to meet planned installed reserve margins, if appropriate

The great majority of existing PJM generators and their characteristics are pre-defined through the ABB annual PROMOD release. It is generally a small percentage of the existing PJM capacity that needs to be modified. Existing PJM capacity resources may need to be retired within the 15-year study window and these will be modeled consistent with the official PJM retirement summaries posted at PJM.com. Within the base data release, a projected retirement date may be made for generators. In the absence of official retirement notification, it is less certain that the units will in fact retire at that time. The retirement date of these units will be changed to a date beyond the study period.

The PJM queue characteristics which indicate that a unit should be considered for Market Efficiency unit specific modeling include in-service units, units with signed ISAs/Interim ISAs/ or not requiring an ISA, and units with an executed FSA or suspended ISA. Generally the dispatch characteristics of a unit with similar capacity, prime mover type, area location, and vintage are copied from the base release, given a new descriptive name and placed at the proper bus location in order to create the representation of the queue units within the database.

The base data release can differ from that described above. Any unit represented within the PJM footprint that does not meet the criteria for being modeled as a unit specific resource will be retired before the Market Efficiency study period.

2.3.2 PJM Generation Modeling – Expected Reserve Margin

Typically PJM compares the PJM forecasted load against the forecasted generation supply to find the Installed Reserve Margin (IRM) for the duration of the study period. It is expected that the projected generation supply will grow in order to at least maintain the forecasted IRM. When load cannot be met with the available resources including Demand Side Response, due to system isolation or constraints, emergency energy is scheduled above the high dispatch limit of local (nearest electrically) resources and priced based on a user setting. Given the emergency energy dispatch block is fictitious, it is generally not desirable to have it as it represents a penalty for not having adequate generation deliverable to localized loads. To minimize the likelihood of emergency energy, adequate reserve margins should be maintained. Beginning with the 2014 Market Efficiency cycle, the supply resources included within the PROMOD database now include FSA level units. This makes it much less likely that PJM will run short of the reserve margin during the Market Efficiency study period.

For Market Efficiency modeling, similar methodologies are used to determine the forecasted PJM reserve margin as is employed by the Resource Adequacy Planning Department. The methodology differences between Resource Adequacy Planning and the Market Efficiency to determine forecast reserve margin involves the additional generation expectations by the beginning of each planning period. The Resource Adequacy Planning's typical method utilizes a full capacity probability multiplier for each generation resource within the active queue. This multiplier is based on what studies have been completed for each project and is called the commercial probability. Market Efficiency relies on the full capacity value of additional units added as part of the unit specific plan discussed in the last section and uses active queue projects that have signed ISAs or FSAs. The existing capacity used as the starting point for the Resource Adequacy Planning reserve margin determination only includes existing internal generation capacity cleared in the RPM market. The "existing" capability of units used in Market Efficiency modeling may include additional energy only units and external capacity. The total unit capability can differ between the two constructs. Once a view of PJM's capacity supply and demand is achieved, given the objective that the Market Efficiency modeling will meet the reserve requirement, the next step is to make up for any generation shortfall. Again, with the revised methodology of explicitly including FSA level units, it is much less likely that there will be a reserve margin shortfall.

2.3.3 PJM Generation Modeling – Generator Scaling

This section discusses how generation is added to the PJM system in order to maintain planning reserves within the Market Efficiency Analysis. The active generation queue is representative of the type and location of generation that is likely to be constructed. The intention is to place the additional generation at bus locations that are designed as generation outlets in proportion to their capability, and to not disrupt typical flow patterns, but to over time affect inter-area flows as would be expected from the queue composition.

2.3.3.1 Processing the Generation Queue for Scaling

Active generation queue projects that are not part of the unit specific plan are eligible to impact the location and type of generation that gets scaled for meeting the PJM reserve margin. The capacity values of the remaining queue projects are aggregated by unit type and region to determine a percentage by region and unit type that is the basis for unit scaling. See Table 1 for a sample table of these percentages.

Table 1 – Region and Unit Type to Maintain Reserve Margin

Region	Nuclear	Coal	Gas	Oil	Wind	Other Renewables	Total Region
AECO/DPL/JCPL/PECO/PSEG	0.8%	0.2%	18.1%	0.0%	0.6%	1.1%	20.7%
AEP/APS/COM/DAY/DUQ/ATSI/DOEK	1.0%	4.2%	18.7%	0.0%	11.2%	2.6%	37.6%
BGE/PEP	3.4%	0.0%	13.4%	0.0%	0.0%	0.0%	16.8%
DOM	0.0%	0.0%	9.7%	0.0%	0.3%	0.1%	10.1%
ME/PN/PPL	0.0%	0.1%	13.8%	0.0%	0.6%	0.3%	14.8%
All Regions	5.2%	4.4%	73.6%	0.0%	12.6%	4.1%	100.0%

In this sample table, 9.7% of the active queue capacity not already specifically modeled is in the Dominion region projected to use gas as the primary fuel. Furthermore, if 3700 MW of capacity was needed to maintain the reserve margin for a particular year, approximately 359 MW (3700 * .097) of capacity would be added to the existing Dominion region gas units (including any unit specific additions). The 359 MW of additional capacity would be allocated to the existing Dominion region gas units in proportion to the existing Maximum Capacity value.

2.4 Demand Response

In the PJM Market, Demand Side Response (DSR) is able to participate in the RPM capacity market, the Day-Ahead, Real-Time Market as well as Ancillary Services market. Effective with the 2014/2015 Delivery Year the DSR product types Annual, Limited, and Extended Summer were introduced and the traditional ILR resources were phased out. Additionally, effective with the 2018/19 Delivery Year two other products were introduced, Base Capacity and Capacity Performance.

With respect to PROMOD modeling the main differences between the resources are the contractual availability requirements. The availability is described in the table below:

Table 2: Demand Resource Product Type Availability

Limited DR	Limited DR is available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time.
Extended Summer DR	Extended Summer DR is available for an unlimited number of interruptions during an extended summer period of June through October and the following May, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time.
Annual DR	Annual DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April.
Base Capacity DR	Base Capacity DR is available for unlimited number of interruptions during June through September in the Delivery Year and will be capable of maintaining such interruption for at least a 10 hour duration between the hours of 10:00 AM to 10:00 PM Eastern Prevailing Time.
Capacity Performance DR	Capacity Performance DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.

Source: http://pjm.com/~/media/documents/manuals/m18.ashx, pg 61

Initially the annual and extended summer product types were developed to enhance the reliability of DSR products, enabling them to be available during longer periods throughout the year – instead of just the summer period. When the RPM auction transitioned to the Capacity Performance product, the Base Capacity DR and Capacity Performance DR were added in order to continue that enhancement. Note that available period for the Base Capacity DR and Limited DR product and also the Capacity Performance DR and Annual DR are the same.

A zonal level forecast of each of the DR resource types can be obtained from Table B-7 of PJM's Load Forecast Report. Market Efficiency models these products as generation resources in PROMOD. Three PROMOD resource types are defined for each zone, with availability of these resources consistent with the periods of the Limited DR, Extended Summer DR, and Annual DR. Because the available time periods are the same, the Base Capacity DR and Capacity Performance DR are mapped to the Limited DR and Annual DR resource types, respectively.

The DSR resources are modeled as discrete resources based on product type, state, transmission zone and historic LMP trends for the buses used to represent withdrawal locations for DSR loads. The load busses in the PROMOD simulation are selected based on recent registration data. DSR providers are required to register the sites being used to meet their DSR commitment for each product type prior to the start of the delivery year. The actual sites are typically at distribution voltage and are subject to change. Consequently, for the PROMOD simulation DSR resources are distributed to approximate the nearest transmission supply station to the registration sites which are typically mapped at the zip code level. Zones with a lot of historic price separation will typically be mapped to more discrete resources within PROMOD to allow for localized response to transmission bottlenecks.

Because of recent changes in the RPM market treatment of Demand Response, there is limited history on the pricing performance of the current demand response products. There is a higher % of cleared annual and extended summer DR, however willingness of these products to participate in the energy market is not known yet. Consequently, while availability throughout the delivery year distinguishes each product within PROMOD, they are modeled as an emergency resource with a very high dispatch price. Given the resource supply assumptions are long with the inclusion of FSA units, it was reasonable to assume that DR would be dispatched last in the model and a price profile would not add additional modeling accuracy.

2.5 Fuel Pricing

This section provides information that will be helpful to understand the database setup and how fuel prices are presented in the input assumptions. Fuel price assumptions are reviewed internally with PJM's Chief Economist and with PJM members through TEAC Committees.

Coal unit fuel is defined at the unit level and represents the burner-tip cost. While there are monthly values defined, they typically are the same value for the year and change on the year boundary. Because coal prices are defined at the unit level, any level change in coal prices would mean adjusting all coal units in the active footprint. Coal price levels reported in TEAC presentations are shown in annual PJM plant average burner-tip prices.

Gas prices are defined at the regional level and then mapped to individual units. The regional prices are comprised of a commodity price (i.e. Henry Hub) coupled with a transportation adder. Each of the constituent pieces changes on a monthly basis for the duration of the price strip. When changing gas price, the commodity price has been modified and the regional basis has not. Changing the commodity price has the effect of changing gas prices for all units within the database. The average annual commodity price is reported in TEAC presentations.

Oil prices (Oil-L, Oil-H, and Diesel) are defined at a global level and mapped to individual units. The oil price varies monthly for the entire strip. When changing oil prices the commodity price is changed, which propagates for each oil unit within the database. The average monthly commodity price is reported in TEAC presentations.

2.6 Emission Pricing

Emission pricing refers to the ($/Ton) price adders needed to account for the incremental cost of effluent release. Emission price assumptions are reviewed internally with PJM's Chief Economist and with PJM members through TEAC Committees.

Effluent costs for sulfur dioxide (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), and mercury (Hg) are available. In some cases several different price strips (i.e. NOx annual, NOx seasonal) are available for the same effluent. This allows for varying effects on different units when mapped appropriately, representing different regulatory constructs.

2.7 Development of the Power flow Topology

The PJM Market Efficiency process utilizes a near term and future base power flow topology. The near term system topology is derived from the latest MMWG series of cases. PJM will confirm and or update the near term system topology typically only for changes or additions to transmission lines, transformers, and switching stations.

The future system topology is derived from the most recent RTEP case which already includes all approved upgrades. Most of the upgrade studies for Market Efficiency Analysis will utilize this topology to study the value of a project. The RTEP Baseline project list can be found at the following link:

http://pjm.com/planning/rtep-upgrades-status/construct-status.aspx

PJM will review any significant upgrades, such as Backbone upgrades, and include in future system topologies as appropriate.

Prior to adding any new generation projects to the model, PJM will verify any network upgrades associated with the generator. The network upgrades assigned to a project as well as construction milestones for the completion of network upgrades can be found in the Schedules E and F of the Construction Service Agreement (CSA).

Transmission outages are not typically included in the Market Efficiency base case. If a planned outage is of a longer duration and the outage period overlaps the period in which an economic upgrade is being evaluated it may be studied as a sensitivity scenario. The decision to study the sensitivity would be based on how the outage period overlaps with the commissioning of the economic upgrade, and the anticipated impact of the outage on the economic project. Power flow analysis will be conducted prior to the economic simulation to determine outages that may impact the economic project.

2.8 Event Modeling

The following guidelines outline the process for determining which facilities will be monitored for the Market Efficiency Analysis.

1. PJM will initially monitor all transmission facilities that are on PJM's monitored facility list The lists of PJM monitored lines and substations are available at http://www.pjm.com/markets-and-operations/transmission-service/transmission-facilities.aspx.

2. The set of contingencies for any monitored facilities are obtained based on historical analysis of real-time constraints. Data for real-time constraints and associated shadow prices is available at http://www.pjm.com/markets-and-operations/energy/real-time.aspx.

3. Initially, PJM will monitor all binding non-generator constraints from the previous market year. The event list will be further reduced based on constraints that are not practical to model within PROMOD such as those that involve closing normally open breakers, switching load or result in loss of generation.

4. PJM will also review the NERC Book of Flowgates (BOF) to identify additional constraints that should be modeled. The BOF is especially useful in identifying flowgates that are jointly controlled by PJM and another region, specifically market coordinated flowgates. These are generally external constraints for which PJM generation has a significant Transfer Distribution Factor (TDF). However, the BOF is also a good source for identifying internal flowgates. Generally, flowgates are selected where PJM is either the reliability coordinator, controlling area or transmission Provider. For economic modeling contingencies from the BOF will only be selected that are defined as NERC Category A (System Normal) and Category B (N-1) contingencies. (See Standard TPL-001-0.1 Table 1. Transmission System Standards – Normal and Emergency Conditions)

5. Upon developing the final set of monitored/contingency pairs, preliminary PROMOD simulations are run for the near term and future system topologies. This analysis is done to enhance the performance of the PROMOD Simulation through eliminating contingencies that have a low likelihood of binding in simulations. To decrease simulation run-time, constraints that are not loaded significantly pre- or post-contingency, and thus unlikely to contribute to congestion may be removed from the event file for future simulations.

6. Constraints that have uncharacteristically high congestion compared to historic congestion results will be further analyzed to identify causes. Erroneous congestion can be caused by any number of factors including errors in the load mapping, unrealistic generation maintenance schedules or forced outages, errors in the event modeling, unrealistic loop flow contributions due to static load and static generation modeling, etc.

7. PJM will review transmission facilities with historical congestion in the past few years and include as appropriate.

2.9 Special Operating Procedures

In general non-market based operations are not represented in the Market Efficiency process. The PROMOD application does not have the capability at this time to represent many short-term actions by operators to relieve overloads on lines. The model limitations do not generally present a significant problem for evaluating a project to identify longer term solutions to transmission problems. In some cases where a reliability solution has not already been identified, where practical PJM may model parts of an SPS in order to better represent historical and current congestion patterns. An example of an SPS that would be incorporated into the modeling is where there is a contingency resulting in overloading a secondary line, and consequently both lines are taken out in actual operations. For a complete description of operating protocols for specific facilities see PJM Manual-3 at

http://www.pjm.com/~/media/documents/manuals/m03.ashx.

2.10 Transmission Facility Ratings

To the degree possible, PJM models transmission facility operational ratings unless a planned/completed project is identified to justify a rating change. Facility ratings are posted on the PJM OASIS System information page at

https://edart.pjm.com/reports/PJM_Line_ratings.txt.

In cases where operational ratings cannot be identified, the model will default to the rating from the power flow. The process for updating the facility ratings is described below.

1. PJM compares the ratings in the near term system power flow model to the most recent set of operating ratings posted to the PJM OASIS. PROMOD only has the capability of representing two sets of ratings defined by the summer (April – September) and winter (October – March) Periods. The operational ratings are categorized in the following way:

    a. Day and Night

    b. System Operating state : Normal, Long-term Emergency (LTE), Short-term Emergency (STE) and Load Dump

    c. Ambient Temperature in Degrees Fahrenheit: 32, 41, 50, 59, 68, 77, 86, 95.

    The summer facility ratings modeled in Market Efficiency are the daytime, 95 degree, Normal/LTE ratings sets. This is consistent with the rating set used in the MMWG summer peak power flow case. The winter facility ratings modeled in Market Efficiency are based on the daytime, 32 degree, Normal/LTE ratings sets. For some facilities the operating ratings will be defined for both ends (END A & B) of the transmission line. This is typical of inter-tie facilities where there is more than one transmission owner, or cases where substation or protective equipment on the line itself further limit the transmission line's capability on either end. Transformers are also defined in the operating ratings set based on the high and low side of the transformer. PROMOD only represents power flow topological detail at the level of branches, busses, and transformers. Consequently, for Market Efficiency Analysis, PJM models the most limiting end rating for both the transmission lines and transformers. In cases of transmission facilities where the OASIS operating rating is not defined, PJM will use the rating from the same MMWG Series and model year. It is important that all the ratings for monitored facilities be validated for proper coordination. For example when there are two transmission lines with highly correlated flows or a high outage transfer distribution factor, and only one of the lines has a winter rating it is possible that the other line will bind in the simulation as flows through the path increase. To avoid this, PJM validates all of the monitored facilities to ensure proper coordination and remove unintended congestion bottlenecks.

2. The process for validating the ratings set used in future year topologies includes impacts from transmission upgrades. However to determine anomalies in the RTEP power flow ratings, PJM will still perform a comparison between the RTEP power flow ratings and the near term operational ratings. The method for determining which rating to use depends on whether there is a planned upgrade or transmission planning study (e.g. sag study) that can justify a significant change in the RTEP rating. The list of transmission upgrades can be found at

   http://pjm.com/planning/rtep-upgrades-status/construct-status.aspx.

3. The following describes various scenarios that lead to a different treatment of ratings in future year topologies in Market Efficiency analysis.

   a. No Transmission Upgrade

      i. Market Efficiency will default to the ratings set used in the current year power flow model or the most recent ratings published on PJM OASIS.

   b. No Transmission Upgrade and a change in impedance characteristics

      i. PJM will confirm with the Transmission Planning group and if necessary the transmission owner whether the new ratings and impedances are valid to be represented in the economic model.

   c. Transmission Upgrade resulted in a change in rating

      i. PJM will use the summer rating defined in the RTEP power flow model for summer facility ratings.

      ii. PJM will use the winter rating defined in the RTEP Winter power flow model.

d. Sag Study results in a change in rating

i. PJM will confirm whether the change in rating should be modeled in the economic analysis and reflect the decrease or increase in rating identified in the sag study.

2.11 Reactive Ratings Modeling

Post-contingency voltage constraints can limit the amount of energy that can be imported from and through portions of the PJM RTO. For real-time operation, an automated online full AC security analysis transfer study determines Transfer Limits. In PJM markets and Market Efficiency, reactive transfers are limited through modeling of proxy interfaces composed of transmission lines. The transfers across an interface are the MW flows across the transmission paths. The transfer limits are the MW transfer beyond which reactive and voltage criteria are violated. The reactive limits simulated in PROMOD are either the pre-contingency MW limits, or post-contingency MW limits. Although Market Efficiency evaluates a planning model that does not have all the variability observed in operations it is still necessary to limit MW flows over these interfaces to get a reasonable representation of the unit commitment and dispatch in simulation results. While PROMOD simulates generator outages and hourly load shapes, it is not practical to simulate hourly reactive limits. However, it is possible to simulate seasonal limits to represent the impact of changes in generation dispatch and load levels on the systems reactive capability between the winter and summer. Using applicable power flow models for the study years simulated in PROMOD, PJM performs Power Voltage stability analysis (PV) to determine Reactive Limits. For nearer term analysis and better congestion benchmarking, the calculated limits may be adjusted based on historical analysis of flows on the interfaces and corresponding limits. The following are the steps used for determining reactive interface limits in the Market Efficiency process:

1. PJM will initially determine a set of study assumptions to be used in the PV analysis. This includes relevant generation and transmission topology for the study year being simulated. Furthermore, the list of contingencies, transfer study areas, interface definitions, monitored busses and associated voltage settings are determined for each interface being studied. Once study assumptions are finalized, PJM will perform a Power Voltage (PV) analysis using the Market Efficiency summer (and winter when available) near term and future system power flow topologies.

2. The limits calculated in the PV analysis are very sensitive to the initial generation dispatch in the power flow, which may not represent a significant number of hours where generation is dispatched within PROMOD. With the inclusion of FSA units in the PROMOD unit commitment and dispatch, these additional units are allowed to be dispatched for the PV analysis whereas they are normally off-line in the RTEP summer peak case. The PV calculation is performed as follows:

a) Perform a reactive screening on the RTEP case using PSSE (cntb, tap adjustments, etc). The case reactive profile, devices, and settings are reviewed and adjustments are made as necessary. This includes voltage profiles, status of reactors, switch shunts, fixed shunts, reactive reserves on generators, conflicting set points, etc.

b) Perform a Security Constrained Economic Dispatch (SCED) on the case using approximate generation cost data from public sources and monitoring 100 kV and above for entire PJM only. PJM will use a subset of contingencies that are pertinent to the study.

c) The SCED case will be used with PJM built PSS/E-based tool to get a series of increasing transfer cases for each interface.

d) TARA program is used to perform an AC contingency analysis on the series of transfer cases.

Notes:

1) Additional modeling details are included in **Appendix A – PJM Reactive Transfer Interfaces Parameters** for each reactive interface:

- Transfer Interface Sources
- Transfer Interface Sinks
- Monitored 500 kV Buses for voltage drop
- List of contingencies currently screened by Operations Planning.

2) PJM performs contingency analysis using the planning monitor and contingency files on the reference power flow case used in a particular study. A subset of contingencies is chosen for SCED based on the set that causes a thermal or voltage issue when run on the reference case. These selected contingencies are combined with contingencies currently screened by Operations Planning (the ones associated with each reactive interface) to form the contingency file that will be used in the SCED and in the reactive interface limit determination.

3) Load Tap Changers (LTC) are allowed to adjust in the solution throughout reference case and transfer case setup. The only time LTC's are locked is when determining the transfer limit (for contingency). Case by case throughout the process it is common that LTC adjustments are needed to achieve convergence. The issues may be within or outside of PJM.

4) During transfer case creation, the "Low voltage threshold to start scaling load down" setting is 0.8 pu. However, bus voltages are typically above this 0.8 pu threshold under normal operating conditions.

5) During testing for limits on the transfer cases, the planning monitor/contingency file and operation's monitor/contingency file for each interface are used to monitor PJM. Limits based on the operation's monitor elements are always considered valid limits to the transfer. PJM will determine whether other observed voltage issues are related to the reactive interface limit in question and therefore eligible to set the limit.

6) Load level is not increased in the base case but will change in transfer cases. The sink load levels can be higher than 90/10 loads. The intent of the load increases is to create transfers through the interface in a manner that stresses the interfaces with flows.

7) PJM uses Transmission Planning Emergency Low Vmag Limits and VDrop limits which are contained in the planning analysis files used in conducting analyses. An additional setting that is used sets the pickup of generation contingencies proportional to unit MVA on generator's > 100MW.

8) When simulating transfers, PJM does not allow the system slack to cover loss changes. The source generation scale compensates for these losses.

9) Pumped Storage units generate at fixed levels typical of a peak demand operation. They do not participate on the economic dispatch in the SCED case.

10) Wind units use average capacities based on typical locational profiles. Typical resulting wind outputs range from approximately 10% to 25% of power flow unit Pmax. Solar units used 38% of Pmax.

11) The economic cost data assigned to each generator comes from planning production cost simulations of the PJM system. For units that do not exist in the production cost database, cost data of similar plants is used (criteria to match data to new units include unit size, fuel type, technology type, and age

3. PJM will determine historical Reactive Interface ratings for all reactive ratings for the past two years. Average reactive ratings will be calculated for different periods including, summer, winter, and months in which transmission outages are at a minimum. Historical limits are provided at the following link http://www.pjm.com/pub/operations/reactive-transfers. This file contains both hourly transfer flows and limits. Only the limits are used for each interface.

4. PJM calculates limits on a current system model and a future system model and calculates a delta between the two sets of calculated limits for each interface. This delta may be used as a reference to be applied to the historical limits for each interface. The winter limits may be derived from the delta between historical summer and winter values applied to the final summer limit.

5. For future simulation years, where there are significant changes to both the PJM and external transmission system, PJM does additional validations on the results of the PV analysis by performing a delta analysis for specific transmission upgrades and generator retirements using a near term power flow model. Because there are many factors that can influence the calculated limits, doing a delta analysis provides more confidence in the drivers for changes in limits and ultimately the congestion identified through PROMOD simulation.

6. PJM will perform preliminary Market Efficiency simulations to determine market flow and external PJM flow contributions on reactive interfaces. These simulated flows will be compared to historical flows and may be used to adjust Market Efficiency reactive limits determined in previous steps.

2.12 Transaction and External Region Modeling

2.12.1 Merchant Transmission Facility Modeling

To adequately represent present and future rights to the transmission system it is necessary to model Merchant Transmission within PROMOD. Merchant Transmission can consist of both internal facilities as well as those that provide an interconnection to non-PJM control areas. Furthermore the facilities can either be D.C. or fully controllable AC facilities. Similar to Generators, Merchant Transmission projects must also undergo an interconnection study process. Transmission Injection Rights (TIRs) or Transmission Withdrawal Rights (TWRs) are defined at the Point of Interconnection between the facility and the PJM Transmission System. The amount of rights awarded is dependent on the capabilities of the facilities (Firm or Non-Firm) and the upgrades necessary to accommodate other interconnection customers/developers interconnection request. Unlike generation projects, holders of TIRs and TWRs can be assigned cost allocation for new RTEP Baseline projects based on the firm service level awarded the project.

Prior to modeling the Merchant Transmission Facility, Market Efficiency will confirm the modeling of the upgrades associated with the project. Unless the non-PJM control area that is either supplied to or delivered from is modeled in Market Efficiency with full dispatch of its load and generation, then only up to the firm capability of the Merchant Transmission Facilities will be represented in Market Efficiency to not overstate responsibility for transmission congestion costs.

Similar to internal loads, the transactions scheduled over merchant transmission facilities have some variability throughout the day and seasonally. Current PROMOD modeling uses nomograms to limit both the amount and direction of interchange over the merchant facilities. This allows flows on the merchant facilities to be dictated by power system economics, while remaining within the merchant transmission agreement characteristics.

2.12.2 External Region Modeling

PJM models the surrounding external regions within the active footprint where appropriate in Market Efficiency. The current process coordinates with PJM Interregional Planning to obtain an external region representation that includes multi-party transactions with commitment and dispatch hurdle rates defined between pools. This allows for economic transactions to flow between the active pools within the simulation.

In addition to actively dispatching some external regions, PROMOD uses a set of user-defined scaling regions to balance load and generation within inactive areas. To do so, PROMOD will automatically scale generation uniformly to balance the load and losses in the inactive regions. Because in the original power flow model, inactive areas may have balanced their load and generation through interchange with actively dispatched areas, uniform scaling can result in implausible flows on the transmission system, specifically tie-lines. For example, zones adjacent to scaled regions may have high levels of parallel flow as a result, and the congestion results can be distorted. To mitigate the impacts of uniform scaling, and adjust for assumed levels of interchange in the imported power flow model, it may be necessary to either scale load and generation or model artificial injections/withdrawals in these regions before importing the power flow into PROMOD. Once the case is imported into PROMOD, PJM sets up scaling regions such that the amount of scaling performed within PROMOD is minimized. As fixed transactions are modeled in PROMOD to represent additional levels of interchange beyond the base case, consideration is given to confirm that the inactive power flow regions' dispatch is consistent with the simulation.

2.12.3 External DC-TIE Modeling

There are several DC ties in the Eastern Interconnect that are not in the Market Efficiency PROMOD simulation's active footprint. There can be significant amounts of flow as well as congestion attributed to the DC ties when the scaling regions are not balanced appropriately. When modeling only the PJM footprint, the congestion on the external DC ties represents the penalty for not meeting the intended DC tie schedule, but will generally not re-dispatch internal generation. However, when there are significant transfers of MW between inactive regions, the transmission system loading in active regions as well as congestion results can be skewed. To prevent these impacts, PJM reviews the flows on these DC ties to identify how much the external world is perturbed from the original PSSE power flow model. In addition, to simulate normal DC tie flow, a static injection or withdrawal may be modeled on the sending/receiving ends of the DC tie. When the external DC Tie is not deviating significantly from schedule or the additional flow is not expected to impact the PJM tie-lines and parallel flows within the footprint, PJM may just expand the limits of the DC tie so that it doesn't bind for schedule deviation. These techniques help to minimize the amount of scaling PROMOD performs automatically, and enables PJM to better control the impact of inactive areas on the internal footprint. Ideally, because the regions connected by the DC ties are static, the DC tie flow should closely represent the schedule modeled in the power flow for the snapshot of the system. However, when this is not practical given other modeling assumptions, PJM will employ the techniques described above to get a reasonable representation of static flows in the simulation.

Appendix A – PJM Reactive Transfer Interfaces Parameters

This content has been redacted for CEII reasons. For full details please see the CEII version of the document at the link below

http://www.pjm.com/planning/rtep-development/market-efficiency/economic-planning-process.aspx