



Business Rules
for Economic Planning Process

A. Information Posting

1. PJM will calculate and post gross congestion costs by constraint for each constraint causing real-time off-cost operations. Gross congestion will be calculated as the product of the constraint shadow price times the load MWs at each load bus in the affected area times the load bus dfax where the affected area is defined as any bus with a DFAX of 3% or greater.
2. The monthly gross congestion costs will be compared to the following Initial Threshold values:

<u>Constraint Operating Voltage</u>	<u>Initial Threshold</u>
greater than 345 kV	\$2,000,000/month
100 kV up to and including 345 kV	\$ 250,000/month
less than 100 kV	\$ 100,000/month

3. PJM will calculate and post the Unhedgeable congestion costs for any constraint which has monthly gross congestion costs which exceed the applicable initial threshold value. Unhedgeable congestion costs will be calculated by taking the sum of load MWs at each load bus in the affected area times the relevant load bus dfax minus the sum of economic generation MWs at each generator bus in the affected area times the relevant generator bus dfax minus the sum of FTR MWs, and multiplying the resulting MW by the constraint shadow price. Economic generation is generation which is available and on-line and which, at its current level of output, has a bid price no greater than the PJM system marginal price. Self-scheduled generation is assigned a bid price of zero in the determination of economic generation MW.
4. The monthly unhedgeable congestion costs will be compared to the following market threshold values

<u>Constraint Operating Voltage</u>	<u>Market Threshold</u>
greater than 345 kV	\$100,000/month
100 kV up to and including 345 kV	\$ 50,000/month
less than 100 kV	\$ 25,000/month

5. For any constraint which has monthly unhedgeable congestion costs which exceed the market threshold, PJM will post the unhedgeable congestion costs, economic generation MW and generic cost estimates to relieve the constraint. If the constraint is a thermal limitation then PJM will



post the first and second most limiting components of the constrained facility.

6. This information will be posted for informational purposes only and may be considered as informal input to the market efficiency analysis.

B. Identification of Upgrades for Economic Purposes

7. Upgrades will be identified for constraints which have an economic impact but for which no reliability-based need has yet been identified. Such upgrades will be recommended for inclusion in the PJM RTEP based on the overall results of the Market Efficiency analysis described in Section C.
8. The market efficiency analysis will also compare the cost and benefit of reasonably accelerating or expanding an upgrade which is already included in the RTEP as a reliability-based upgrade if that upgrade is also identified as one which can relieve a constraint shown to have an economic impact. Reasonable acceleration or expansion of such an upgrade may be recommended for inclusion in the PJM RTEP based on the overall results of the Market Efficiency analysis described in Section C.
9. Constraints having an economic impact include but are not limited to the following:
 - a. Constraints causing significant historical gross congestion
 - b. Constraints causing significant historical unhedgeable congestion
 - c. Constraints causing a pro-ration of Stage 1B ARR requests
 - d. Constraints causing significant simulated congestion as forecast in market efficiency analysis

Upgrades for constraints causing a pro-ration of Stage 1A ARR requests will be recommended for inclusion in the RTEP with a recommended in-service date based on the 10-year Stage 1A simultaneous feasibility analysis results. This recommendation will also include a high-level analysis of the cost and economic benefits of the upgrade as additional information but such upgrades will not be subject to market efficiency cost/benefit analysis.



C. Market Efficiency Analysis

10. Market Efficiency analysis will be performed as part of the overall Regional Transmission Planning Process (RTEP) and will be performed after the completion of the reliability portion of the RTEP.
11. Market efficiency analysis is a comparison of the cost of an upgrade to the projected economic benefit of the upgrade where the upgrade is identified as one needed to relieve a constraint or multiple constraints having an economic impact.
12. PJM will calculate and post the change in the following metrics to quantify the economic benefits of an upgrade:
 - a. Total PJM production cost (fuel costs and variable O&M costs)
 - b. Total PJM load payments (load MW times load LMP)
 - c. Total PJM generator revenue (generator MW times generator LMP)
 - d. Zonal load payments (zonal load MW times Zonal LMP)
 - e. Total PJM FTR credits (as measured using currently allocated ARRAs plus additional ARRAs made available by the upgrade)
 - f. Zonal FTR Credits (as measured using currently allocated ARRAs plus additional ARRAs made available by the upgrade)
 - g. Total PJM Transmission system losses
 - h. Total PJM capacity payments (relevant only for locational capacity market model)
13. Energy Market-related benefits as described in Items 12a, 12b, 12c, 12d, 12e and 12f will be quantified using a market simulation tool which simulates the hourly security-constrained commitment and dispatch of generation to meet load while recognizing all transmission system limitations. Simulations will be made with and without the upgrade under various sensitivity scenarios to quantify the benefits of the upgrade.

The benefits described in 12a, 12b, 12c, 12d, 12e and 12f are different energy market efficiency metrics which are not additive benefits. Each of these metrics, as well as other metrics which can be derived from these, will provide a more complete understanding of the overall economic impact of the upgrade being studied. It should be recognized that they are not all equally appropriate in deciding whether an upgrade will reduce total costs to customers.

The change in production cost is the change in fuel cost and variable O&M costs associated with changes in PJM generation dispatch pattern. It does not represent the change in payments made by load customers since load customers pay the marginal price of energy purchased from the PJM spot market.



The change in gross PJM load payments represents the change in payments made by load customers assuming the customers purchase all energy needs from the PJM spot market. It does not include the effect of bilateral hedging or congestion hedging instruments available to load. The change in gross PJM generator revenue represents the change in payments made to generation by load. The difference between total PJM load payments and PJM generator revenues represents the total system congestion charges. If one assumes that all congestion charges are rebated back to load customers in the form of FTR revenues then the change in gross PJM generator revenues provides an estimate of the change in net payments made by total system load assuming no bilateral hedging.

14. The change in transmission losses (Item 12g) will be quantified using power flow models of various load and generation patterns with and without the upgrade. The power flow model which includes the upgrade will also include a revised generation dispatch pattern reflecting the effect of the upgrade on economic generation dispatch.
15. The change in total capacity payments (Item 12h) will be quantified using the PJM locational capacity market model with and without the upgrade effect under various sensitivity scenarios.
16. The total upgrade benefit will be the sum of the energy-related benefit plus the transmission loss benefit plus the capacity payment benefit.
17. Future annual upgrade benefits will be forecast by extrapolation of simulation results.
18. The net present value of annual benefits will be calculated for 10, 20 and 30 years and compared to the net present value of the upgrade revenue requirement for 10, 20 and 30 years.
19. As part of a related sensitivity analysis PJM will develop and post results from transmission studies that explore the impact of using the investment response model results from PJM's anticipated locational capacity construct. This investment model, developed as part of the locational capacity construct filing, yields results that help to identify the location and amount of generation needed to mitigate identified constraints. This sensitivity analysis can then be used for comparison with 'base case' studies that employ a scaling factor applied to existing generation in cases where insufficient generation is planned to meet anticipated load growth. Base case analysis will not model any hypothetical generation.



20. For each transmission project proposed for RTEP, PJM will also post, as soon as practical, the following:
 - a. Anticipated high-level project schedule and milestone dates
 - b. Final commitment date after which any change to input factors or drivers will not result in transmission project deferral or cancellation.

D. Energy Market Simulation Analysis

Measurement of Economic Impact of Reliability-based RTEP Upgrades

21. Annual market simulations will be made for future years 1, 4, 7 and 10. A “base case” set of simulations for each of the four years will be performed using a base set of assumptions regarding hourly zonal loads, projected fuel costs and future generation scenarios.
22. An initial set of simulations will be conducted for each of the four years using the “as-is” transmission network topology without modeling future RTEP upgrades.
23. A second set of simulations will be conducted for each of the four years using the as-planned RTEP upgrades.
24. A comparison of these simulations will identify constraints which have caused significant historical or simulated congestion costs but for which an as-planned upgrade will eliminate or relieve the congestion costs to the point that the constraint is no longer an economic concern.
25. A comparison of these simulations will also reveal if a particular RTEP upgrade is a candidate for acceleration or expansion. For example, if a constraint causes significant congestion in year 7 but not in year 10 then the upgrade which eliminates this congestion in the year 10 simulation may be a candidate for acceleration. The benefit of accelerating this upgrade would then be compared to the cost of acceleration as described below before recommendation for acceleration is made.
26. Steps 19 thru 23 will be repeated using high and low sensitivity cases around the base assumptions regarding hourly zonal loads, projected fuel costs and future generation scenarios.



Measurement of Upgrade Benefit

27. Annual market simulations will be made for future years 1, 4, 7 and 10. A “base case” set of simulations for each of the four years will be performed using a base set of assumptions regarding hourly zonal loads, projected fuel costs and future generation scenarios.
28. An initial set of simulations will be conducted for each of the four years using the as-planned transmission network topology as defined by the most recent RTEP.
29. A second set of simulations will be conducted for each of the four years using the as-planned transmission network topology plus the upgrade being studied.
30. A comparison of these simulations will identify the benefit of the upgrade in years 1, 4, 7 and 10. Annual benefits within the 10-year time frame for years which were not simulated would be interpolated using these simulation results. A forecast of annual benefits for years beyond the 10-year simulation time frame would be based on an extrapolation of the market simulation results for years 1, 4, 7 and 10. A higher-level annual market simulation will be made for future year 15 to validate the extrapolation results and the extrapolation of annual benefits for years beyond the 10-year simulation time frame may be adjusted accordingly. This high level simulation of future year 15 may require a less detailed model of the transmission system below the 500 kV level.
31. The net present value of annual benefits for 10, 20 and 30 years will be compared to the net present value of the upgrade revenue requirement for 10, 20 and 30 years to determine if the upgrade is cost beneficial and recommended for inclusion in the PJM RTEP.
32. Steps 24 thru 28 will be repeated using high and low sensitivity cases around the base assumptions regarding hourly zonal loads, projected fuel costs and future generation scenarios.
33. Scenario descriptions and results will be provided for all scenarios and decisions about which upgrades to complete will be made based on the overall results.
34. For each upgrade which is recommended for inclusion in the RTEP, PJM will provide the level of new generation or DSM per region that would eliminate the need for the transmission upgrade.



E. Cost Allocation of Transmission Upgrades Driven by Economics

35. The cost allocation method for transmission upgrades is currently being debated at the FERC and is yet to be determined. The RPPWG is not recommending or endorsing any cost allocation method, pending the outcome of the proceedings at the FERC.