Market Efficiency Process Enhancement Task Force Phase 3

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Knowledge Management Center
May 12, 2020
Planning Committee

MEPETF Background

- Market Efficiency Process Enhancement Task Force
  - Approved to start work in January 2018
  - Address challenges and opportunities for improvements to Market Efficiency process since implementing FERC Order 1000 processes
- Phase 1 completed - August 2018
- Phase 2 completed - April 2019
- Phase 3
  - Benefit-to-Cost Calculations:
    - Separate Energy and Capacity
    - Consider Positive and Negative Impacts
    - Consider Risk
  - New Regional Targeted Market Efficiency Project Process

- Issues addressed via 3 sets of packages. Poll results based on each separate set of packages
  - A -- RTMEP
  - B – Benefit Calculation
  - C -- Window for Capacity Drivers

- 13 Unique Responders
- Representing 110 Companies

Package Owners

- **PJM**
  - A1, B1, C1
- **IMM**
  - A2, ~~A3~~, B2, ~~B3~~, C2
- **First Energy**
  - B4
- **AEP**
  - A4

New RTMEP Process

Design Component	A4 (AEP) 67%	A1 (PJM) 36%	A2 (IMM) 36%
Benefits	Average of past 2 years of historical congestion (Day Ahead + Balancing), adjusted for outage impacts	Average of past 2 years of historical congestion (Day Ahead + Balancing), adjusted for outage impacts	Changes in system wide load cost, net of congestion allocation
Cost	Project capital cost (no discount or inflation rate)	Project capital cost (no discount or inflation rate)	Cost risk considered
Passing Threshold	Four years worth of Benefits (no discount/inflation rate) must completely cover project's capital cost	Four years worth of Benefits (no discount/inflation rate) must completely cover project's capital cost	1.25

New RTMEP Process (continued)

Design Component	A4 (AEP) 67%	A1 (PJM) 36%	A2 (IMM) 36%
Competitive Process Type	Designated to incumbent TOs as exclusions to competitive process.	Sponsorship Model (Competitive window)	Competitive window for projects and/or funding
TMEP Window	Designated to incumbent TOs as exclusions to competitive process.	30-day window, as needed	30-day window, as needed

Benefit Calculation Metric

Design Component	B1 (PJM) 55%	B4 (FE) 20%	B2 (IMM) 18%
Regional Benefit Calculation	50% Net Load Payment + 50% Adjusted Production Cost (Status Quo)	50% Net Load Payment + 50% Adjusted Production Cost (Status Quo)	Changes in system wide load cost, net of modeled congestion allocation
Lower Voltage Benefit Calculation	100% Net Load Payment (Status Quo)	100% Net Load Payment (Status Quo)	Changes in system wide load cost, net of modeled congestion allocation
Energy Benefit Sensitivities	For informational purposes only (Status Quo)	Weighted average, weights based historic variability, etc.	Weighted average, weights based historic variability, etc.

Benefit Calculation Metric (continued)

Design Component	B1 (PJM) 55%	B4 (FE) 20%	B2 (IMM) 18%
Hourly Monte Carlo	Single draw (Status Quo)	Average of Monte Carlo Results	Average of Monte Carlo Results
Capacity Benefit Calculation Simulation Years	RPM and RTEP years	RTEP, RTEP+3 and RTEP+6 (Status Quo)	RTEP, RTEP+3 and RTEP+6 (Status Quo)

Window for Capacity Drivers

Design Component	C1 (PJM) 100%	C2 (IMM) 31%
Cycle Type	24-Month for Energy drivers; 12-Month for Capacity drivers	24-Month (Status Quo)
Proposal Windows Type & Duration	120-day biennial window for long-term Energy drivers 60-day annual short-term window for Capacity exclusive and multi-criteria drivers, when needed	120-day long-term window for Energy, Capacity and multi-criteria drivers; biennial (Status Quo)
Window Timing	Energy drivers: January-April of odd years Capacity drivers: Following the annual Base Residual Auction (BRA)	Annually

Window for Capacity Drivers (continued)

Design Component	C1 (PJM) 100%	C2 (IMM) 31%
Timing and Coordination between Energy Drivers and Capacity Drivers Windows	If the same congestion drivers are identified for both Energy and RPM, then the evaluation of the combined benefits will be performed during the 24-month process used for the evaluation of Energy congestion drivers. The latest available ME base case will be used to evaluate the proposals for such multi-criteria drivers.	Status Quo

Next Steps

- May 12 PC
  - Package Endorsements
- June 18 MRC
  - First Read of Endorsed Packages and Documentation Updates
- July 23 MRC
  - Endorsement of Packages and Documentation Updates

Appendix

New RTMEP Process for Market Efficiency Projects

Market Efficiency Process Enhancement Task Force: Phase 3 PJM Proposal

Nick Dumitriu, Market Simulation

February 4, 2020

Planning Committee

- **Proposing three changes to the market efficiency process:**

1. Create a backwards looking “quick hit” market efficiency process to address persistent congestion not identified in the forward looking planning model (PJM Proposal Package A1)
2. Modify calculation inputs for RPM benefits (PJM Proposal Package B1)
3. Create standalone process to address RPM drivers independent of energy driver analysis (PJM Proposal Package C1)

PJM Proposal – Package A1

Create new RTMEP process to address historical congestion not captured in planning models

Design Component	Status Quo	Proposed Change	Justification
Qualified Projects	No process exists	Projects which resolve congestion on one or more Qualified Congestion Driver(s), with a capital cost under $20 million, to be in service by June 1 of the third summer season	Establish process to fill gap that exists when historical congestion is persistent and not captured in planning models
Qualified Congestion Drivers	No process exists	PJM identified facilities with significant and persistent historical congestion (based on previous 2 years) that are not due to outages, that are not addressed by any planned system changes	
Benefits	No process exists	Average of past 2 years of historical congestion (Day Ahead + Balancing), adjusted for outage impacts	
Cost	No process exists	Project capital cost (no discount or inflation rate)	
Passing Threshold	No process exists	Four years worth of Benefits (no discount/inflation rate) must completely cover project's capital cost	

PJM Proposal – Package A1 (continue)

Create new RTMEP process to address historical congestion not captured in planning models

Design Component	Status Quo	Proposed Change	Justification
Timing and Coordination between TMEP and ME Processes	No process exists	TMEPs will be studied periodically throughout the market efficiency 24-month cycle. Any identified TMEP driver will be reviewed by TEAC and identified solutions will be approved by Board on an as needed basis.	Establish process to fill gap that exists when historical congestion is persistent and not captured in planning models
Unit Retirements in Area of Congestion	No process exists	Announced generator deactivations at time of project recommendation are considered.	
Competitive Process Type	No process exists	Sponsorship Model (Competitive Window)	
TMEP Window	No process exists	30-day window, as needed	

Regional Targeted ME Projects: IMM Packages

Monitoring Analytics

Status Quo: No Process

- Uncertain benefits are highly sensitive to assumptions regarding fuel mix and fuel prices
  - Dramatic changes in projected benefits and costs possible
  - Risk of incorrect answer forced on customers in the form of a regulated rate of return asset
  - Market would be able to correct for a bad investment, same is not true of regulated assets
- LMPs are correct, not a sign of market inefficiency
  - Congestion is the result of least cost security constrained optimization
  - LMP provides the marginal price of energy by location

Package A2

- Proposal is to improve the calculation of benefits in the B/C analysis
  - Benefit measured as changes in system wide load cost, net of modeled congestion allocations
    - Positive and negative benefits (load costs)
    - Accounting for changes in ARR related offsets
    - Use the average of the forecasted benefits
- Cost risk considered in analysis
- 1.25 B/C ratio
- Competitive window for all projects and/or funding

Package A3

- Proposal is to improve the calculation of benefits in the B/C analysis
  - Benefit measured as changes in system wide production cost
    - Positive and negative benefits (production costs)
    - Use the average of the forecasted benefits
- Cost risk considered in analysis
- 1.25 B/C ratio
- Competitive window for all projects and/or funding

AEP Presentation to PJM PC Regional TMEP (Package A4)

PJM PC Meeting February 4, 2020

Description of Package (A4)

1. **Regional TMEP Package (A4) is identical to Package (A1) in all respects except for the process for identifying the solution and selecting the developer**
    a) Package (A1) calls for identification and selection through proposal window
    b) Package (A4) calls for identification and selection without proposal window

Rationale for Package (A4)

1. **Regional TMEP construct is looking to address historical congestion through quick-hit non-greenfield upgrades that can be placed in-service in short order**
2. **Regional TMEP projects must be in-service by third summer after approval**
   a) Limited amount of time to accommodate proposal window planning process
   b) Proposal window unlikely to change the identification and selection decision
3. **Interregional PJM-MISO TMEP planning process has successfully produced half-dozen projects costing $0.12M to $6.70M and assigned to incumbent TOs**
   a) b2971, b2972, b2973, b2974, b2975, b3053
   b) None involve greenfield projects (are non-competitive by FERC’s definition)
      - three involve reconductoring of lines,
      - one involves reconfiguration of ring bus, and
      - two involve replacement/upgrading of terminal equipment.
   c) Expectation that regional planning process will produce similar projects
4. **PJM may not be able to share historical model needed for proposal window since historical model may contain market sensitive information**
   a) Holding proposal window without modeling information is unproductive

Questions ???

Takis Laios (tlaios@aep.com)

Benefit Calculation Metric Used for Market Efficiency Projects

- **Proposing three changes to the market efficiency process:**

1. Create a backwards looking “quick hit” market efficiency process to address persistent congestion not identified in the forward looking planning model (PJM Proposal Packages A1)
2. Modify calculation inputs for RPM benefits (PJM Proposal Package B1)
3. Create standalone process to address RPM drivers independent of energy driver analysis (PJM Proposal Package C1)

PJM Proposal – Package B1

Changes to the capacity benefit calculation

Design Component	Status Quo	Proposed Change	Justification
Capacity Benefit Calculation Simulation Years	RTEP, RTEP+3 and RTEP+6	RPM and RTEP years	Addresses topology and CETL uncertainties beyond RTEP year
In-Service for RPM Market	No restrictions	To be in service prior to June 1 of the Delivery Year for which the Base Residual Auction is being conducted. In the event a transmission expansion cannot be placed in service by this date, PJM will consider capacity market solutions that can be in service before RTEP year.	Ensure projects address a capacity driver by the RPM year

PJM is <u>not</u> proposing changes to the existing energy benefit calculation or rules governing project cost commitments

Summary available here

IMM Proposals: B/C Analysis

PC

IMM

February 4, 2020

Monitoring Analytics

Issues with Benefit/Cost Analysis

- Order 1000 does not require the type of benefit/cost analysis included in PJM's rules.
- Transmission should be built to meet reliability needs in a cost effective and efficient manner.
- Transmission should be built to integrate new generation consistent with PJM deliverability rules.
- PJM's benefit/cost approach results in transmission investments inappropriately displacing new generation.

Issues with Benefit/Cost Analysis

- Current B/C Analysis includes only energy benefit to those zones that would benefit from the project
  - Ignores zones that would be hurt by project.
- To evaluate benefits, need to include all costs of project
  - Include increases in costs

Need to Account for Risk in Benefit/Cost Analysis

- Benefits cannot be accurately projected over a 15 year period with the certainty required to justify a significant transmission project

Need to Account for Risk in Benefit/Cost Analysis

- Benefit assumptions in B/C analysis are not subject to rigorous sensitivity analysis
  - One benefit estimate used in ratio
  - Does not explicitly account for different probabilities (generation build, changes in fuel costs, load change) in ratio
- Uncertainty in assumptions/parameters can be evaluated with a sensitivity analysis
  - Monte Carlo
  - Both Benefits and Costs subject to uncertainty

Regional and Lower Voltage Benefit Calculation: IMM Packages

Monitoring Analytics

Package B2

- Proposal is to improve the calculation of benefits in the B/C analysis
  - Difference in total load costs before and after proposed project, net of modeled congestion allocation
    - Positive and negative benefits (load costs)
    - Accounting for changes in ARR related offsets
    - Use a weighted average of the forecasted benefits, weights based on historic variability
    - Hourly Monte Carlo: replace single draw with average of results
  - Same metric for benefit calculation used for regional and local projects

Package B3

- Proposal is to improve the calculation of benefits in the B/C analysis
  - Difference in total system wide production costs before and after proposed project
    - Positive and negative benefits (production costs)
    - Use a weighted average of the forecasted benefits, weights based on historic variability
    - Hourly Monte Carlo: replace single draw with average of results
  - Same metric for benefit calculation used for regional and local projects

MEPETF Phase 3, Package B4 (First Energy) Proposal

- **Includes elements of IMM's Package B2 & B3 that would calculate Energy Benefit using:**
  - Weighted average of Sensitivities
  - Average of multiple Monte Carlo results

  These process enhancements are important to
  - Substantiating the beneficial value of proposals
  - Moderating extrapolation of benefits far into the future
- **Excludes elements of IMM's Package B2 & B3 that would change the formula for applying Load Payments and Production Costs to Energy Benefit calculation.**
- **Includes timing restrictions for Capacity Market solutions as in Packages B1, B2 and B3.**

Window for Capacity Drivers Used for Market Efficiency Projects

- **Proposing three changes to the market efficiency process:**

1. Create a backwards looking “quick hit” market efficiency process to address persistent congestion not identified in the forward looking planning model (PJM Proposal Package A1)
2. Modify calculation inputs for RPM benefits (PJM Proposal Package B1)
3. Create standalone process to address RPM drivers independent of energy driver analysis (PJM Proposal Package C1)

PJM Proposal - Package C1

Separate capacity and energy driver studies

Design Component	Status Quo	Proposed Change	Justification
Cycle Type	24-Month	24-Month for Energy drivers 12-Month for Capacity drivers	Address capacity driver in time for BRA delivery year
Proposal Windows Type and Duration	120-day long-term window for Energy, Capacity and multi-criteria drivers; biennial	120-day biennial window for long-term Energy drivers 60-day annual short-term window for Capacity exclusive and multi-criteria drivers, when needed	
Window Timing	January-April of odd years	Energy: January-April of odd years Capacity: Following the annual Base Residual Auction (BRA)	
Capacity Driver Criteria	Tied to Eligible Energy Congestion Drivers	Follow existing OATT Att. DD, Section 15 language	Existing procedures outline when transmission solutions are appropriate in RPM
Window Timing and Coordination Energy Drivers and Capacity Drivers	N/A	If the same congestion drivers are identified for both Energy and RPM, then the combined benefits will be evaluated during the 24-month process. Latest available ME base case used to evaluate proposals for such multi-criteria drivers.	

Window: IMM Package

Monitoring Analytics

Package C2

- Status quo except for:
  - Window Timing (Annually rather than odd years)
  - Capacity Driver Criteria: Strictly follow existing OATT Att. DD, Section 15 language

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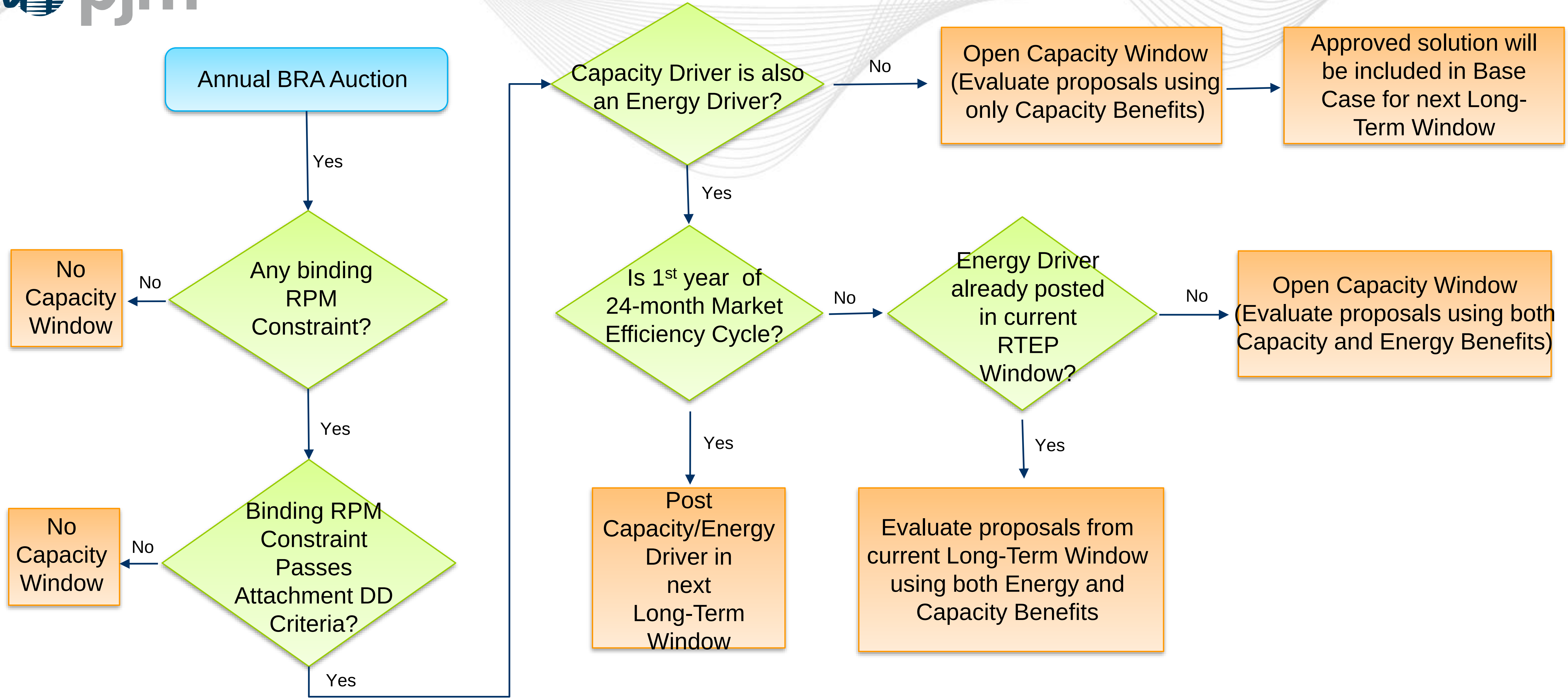
Appendix

TMEP/MEP Comparison

Design Component	MEP	Regional TMEP
Benefit Metric	Net Load Payment Savings	Congestion Cost Savings
Project cost for B:C Ratio	15-years of Annual Revenue Requirement	Total Capital Cost
Project Cost Cap	N/A	$20M
In-service Date	RTEP year or later	3rd Summer Peak
Passing Threshold	1.25:1 NPV over 15 years	1:1 over 4 years
Qualified Congestion Driver	Simulated congestion of $1M or more in each RTEP and RTEP+3 simulation years	Historical avg. congestion of $1M or more in 2 previous years; Simulated congestion less than MEP threshold
Proposal Window	120 days	30 days

Capacity Window Workflow Chart



Regional and Lower Voltage Benefit Calculation: IMM Packages

Monitoring Analytics

Proposal 1: Eliminate The Process

- Current approach favors nonmarket solutions over market solutions to market signals
  - Markets shift risk to those that can best internalize the risk
  - Fundamental premise of PJM markets not represented in efficiency project approach
  - Rate of return assets vs. competitive market responses to prices

Proposal 1: Eliminate The Process

- Uncertain benefits are highly sensitive to assumptions regarding fuel mix and fuel prices
  - Dramatic changes in projected benefits and costs possible
  - Risk of incorrect answer forced on customers in the form of a regulated rate of return asset
  - Market would be able to correct for a bad investment, same is not true of regulated assets
- LMPs are correct, not a sign of market inefficiency
  - Congestion the result of least cost security constrained optimization
  - LMP provides the marginal price of energy by location

Market Efficiency Process Enhancement Task Force – Phase 3

AEP Support for Status Quo of Benefit Calculation

AEP Request of IMM

08/21/19

At the MEPETF meeting on 07/30/19, the IMM referenced market mechanics and examples to argue for changes to the benefits calculation. AEP would appreciate having the same argument made using qualitative and policy principles. Such an approach would better illustrate the issue of economic inefficiencies caused by transmission constraints. AEP would welcome having the following qualitative example used to illustrate the issue raised by the IMM as opposed to using the calculation of market mechanics.

Several loads have joined the same RTO with the expectation that the system would be planned and operated in an economically efficient manner, and thus, all loads are paying the same price for generation at any given point in time.

A transmission constraint results in the middle of the system that causes the cheaper generation that is located upstream from that constraint to run less frequently and at a lower output level than it would if that constraint was not present. That same constraint also now causes the more expensive generation that is located downstream from that constraint to run more frequently and at a higher output level than it would if that constraint was not present.

This transmission constraint effectively provides the loads that are located upstream from that constraint the unintended positive of having exclusive access to the cheaper generation that is located upstream from that constraint. That same constraint also provides the loads that are located downstream from that constraint the unintended negative of having exclusive access to the more expensive generation that is located downstream from that constraint.

Given the initial expectation that the loads joined the same RTO with the expectation that the system would be planned and operated in an economically efficient manner, and thus, all loads were paying the same price for generation at any given point in time prior to the transmission constraint, the fundamental policy question becomes:

> Does the downstream load have the right to advise the regional planner that it wants to fund a transmission upgrade that would mitigate the transmission constraint, thus giving that downstream load access to the cheaper generation that is located upstream from that transmission constraint?
>
> The logical answer would be “yes”!

Understandably, given that this mitigation would effectively increase the cost of the generation that is being accessed by the upstream load (while decreasing the cost of the generation that is being accessed by the downstream load), that upstream load would not be asked to fund that transmission upgrade.

That upstream load, however, cannot prevent that transmission upgrade from being constructed by insisting that their increased generation costs must be taken into account when determining the economic benefits of that transmission upgrade, since the transmission upgrade is eliminating unintended positives that the transmission constraint was providing to the upstream load. For that reason, the upstream load cannot claim as costs the elimination of the unintended positives that the upstream load was receiving as a result of that transmission constraint.

Example of Cost Allocation Methodology Update

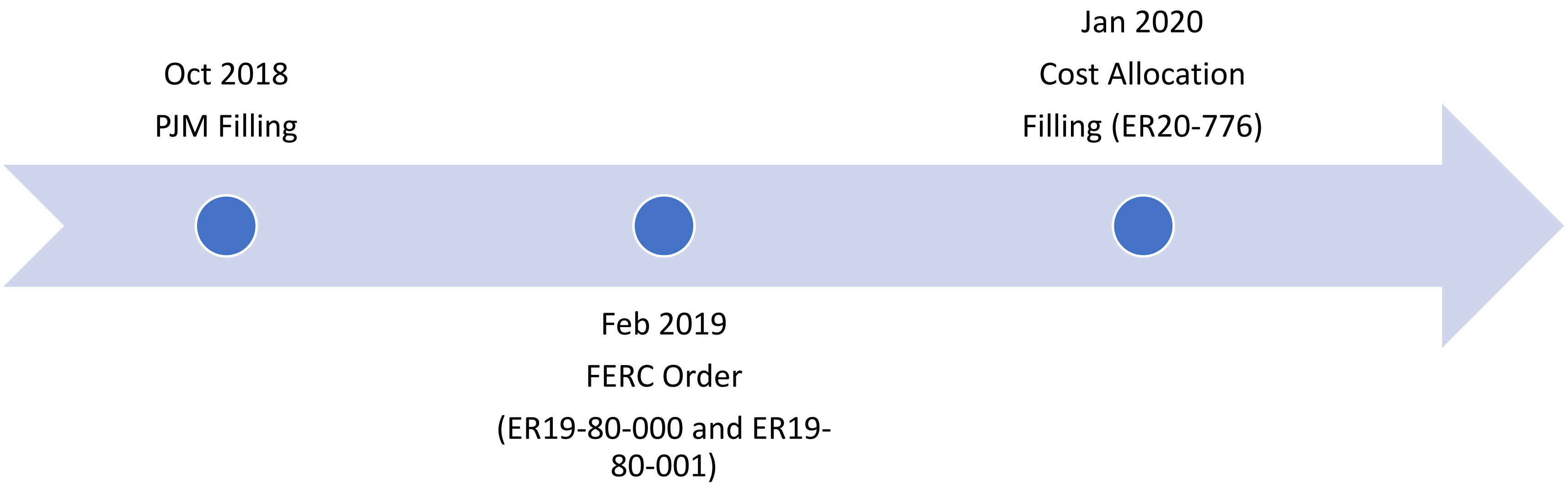
- On October 10, 2018, pursuant to section 205 of the Federal Power Act (FPA), PJM filed proposed revisions to the benefit/cost analysis it conducts in its evaluation of economic-based enhancements or expansions as part of its regional transmission expansion plan (RTEP) process.

- On Feb. 19, 2019 FERC accepted PJM's proposed revisions to the benefit/cost analysis, effective Dec. 10, 2018, (Docket Nos. ER19-80-000 and ER19-80-001)

- ER20-776 filed January 13, 2020 by TOA-AC "Cost allocation methodology for economic projects"

Cost Allocation Process

- Cost Allocation is the responsibility of transmission owners and covered under the CTOA
- Cost Allocation methodology updates discussed at TOA-AC once there is certainty about the planning change that triggered the cost allocation review (i.e. FERC issues order approving the planning change)
- Example: Cost allocation timeline for recent change to the Market Efficiency B/C ratio calculation



FERC Ruling for PJM Filing on Benefit/Cost Analysis (Docket Nos. ER19-80-000 and ER19-80-001)

Item	PJM Modification	FERC Ruling	FERC Reasoning
Regional and Lower Voltage Benefits Calculation Period	15 years from in-service year, capped at RTEP+14	FERC accepted PJM's proposed Operating Agreement (OA) changes.	PJM's proposal to use the same 15-year planning period for evaluating all projects is just and reasonable and not unduly discriminatory modification to PJM's existing benefit/cost ratio calculation, given that the data for periods outside of the planning period are less accurate.
Project Cost Calculation Period	15 years of annual revenue requirements from in-service year, capped at RTEP+14	FERC accepted PJM's proposed Operating Agreement (OA) changes.	