MISO PJM IPSAC

August 21, 2015

Agenda

- Order 1000 Compliance Filing Status Update
- Quick Hit Project Status
- Michigan Interface Analysis (light load study)
- Quad Cities Area Analysis (peak load study)
- Review Feedback from July Meeting
- JOA Metrics and Process Change Proposal

Quick Hit Project Status

Quick Hit Update

- Beaver Channel – Sub 49
  - SCADA Upgrades are complete
  - Next limits (CT / Wave trap) under evaluation

- Michigan City – LaPorte
  - Configuration changes (Bosserman) under evaluation

STATUS - Planned Projects – PJM RTEP

M2M ID	M2M flowgate relieved	Project Description	Congestion Relieved (M $)	Project ID	Project Owner	Target ISD	Status	% Complete
P6	Nelson 345kV	Reconductor 0.4 mi. Replace breaker leads at Nelson	28	s0704	COMED	5/1/2015	In Service	**100**
P9	Byron - Cherry Valley 345kV	New Byron - Wayne 345kV	9.2	b2141	COMED	6/1/2017	Engineering/ Planning	**15**
M7	Cherry Valley - Silver Lake 345kV		0.6					
P12/M11	Miami Fort 345/138	Substation Reconfiguration	7.1	b2634	DEOK	5/1/2017	Engineering/ Planning	**0**
P14/M4	Miami Fort – Hebron 138 kV		6.9					
P17	Bunsonville – Eugene 345kV	Rebuild AEP portion (2.5 mi)	3.8	s0855	AEP	12/1/2015	Engineering/ Planning	**75**

*Congestion relieved is historical congestion costs covering 1/1/2013 – 10/31/2014

On Schedule | Behind Schedule

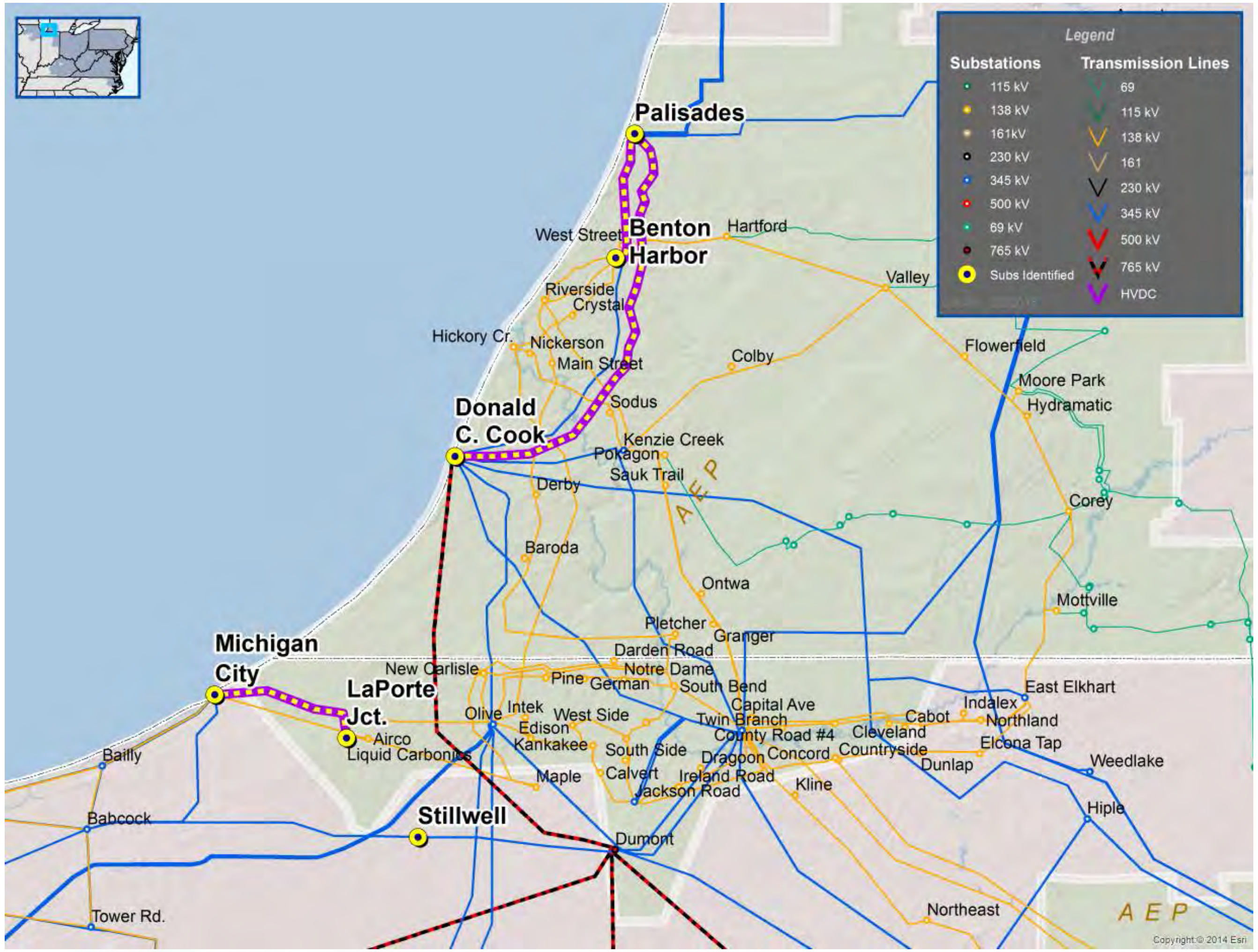
STATUS - Planned Projects – MISO MTEP

M2M ID	M2M flowgate relieved	Project Description	Congestion Relieved (M $)	Project ID	Project Owner	Target ISD	Status
P1	Breed - Wheatland 345kV	Reconductor	94.5	2472	IPL	3/1/2016	Planned
P2	Benton Harbor - Palisades	Terminal Equipment @ METC	61.5	3599	METC	11/1/2015	Planned
P3	Monticello-E. Winamac	Reconductor and terminal equipment	45.1	4810	NIPS	1/1/2015	In Service
P4	Oak Grove - Galesburg 161kV	Oak Grove - Mercer-Sandburg 161kV	37.9	3022	MEC	12/1/2016	Planned
P5	Cook - Palisades	Terminal Equipment @ METC	31.5	3599	METC	11/1/2015	Planned
P7	Rising 45TR1	Sidney - Rising 345kV	20	2239	AMIL	12/1/2016	Planned/Under Construction
P13	Kewanee-Edwards 138kV	Oak Grove - Mercer-Sandburg 161kV	5.9	3022	AMIL	12/1/2016	Planned
P15	Rantoul - Rantoul Jct.	Sidney - Rising 345kV	4.8	2239	AMIL	12/1/2016	Planned/Under Construction
P27	Davenport - E. Calamus	line rebuild	0.8		MEC/ALTW	12/1/2016	
P29	Burr Oak - Plymouth	Burr Oak - Hipple	0.2	3203	NIPS	12/31/2019	Planned
P30	Galesburg 161/138	Oak Grove - Mercer-Sandburg 161kV	0	3022	AMIL	12/1/2016	Planned
M10	Burnham - Munster	Reconfigure as Ring Bus	0.4		NIPS		
M18	Tazwell 345/138	Fargo-Maple Ridge 345 & Fargo 345/138	0.1	2472	AMIL	6/1/2016	Planned

Michigan Interface Analysis

Michigan Interface

- Benton Harbor – Palisades
- Cook – Palisades
- Michigan City – LaPorte



- Study Objectives
  - Evaluate how future configuration & interconnection changes impact congestion (Covert/Segreto interconnection, etc.)
  - Identify potential retirement impacts
  - Study and develop solutions as required
- Study Approach similar to Quick Hit Analysis
- Study timeline: second half of 2015
- Models
  - Joint reliability model – Light Load 2015
  - Regional model market efficiency confirmations - 2015

Study Progress

- Reliability
  - Developed light load as-is powerflows for PJM and MISO
  - Merged powerflows to a joint case for evaluation
  - Shared MON and CON files
  - Baseline reliability analysis underway
- Market Efficiency
  - PJM has moved 2014 Quick Hit model to 2015
  - Working on benchmarking of models between PJM & MISO

Quad Cities Analysis

Quad Cities

- Main driver: 345 kV outages near Quad Cities, IA
  - Summer Peak and high South to North flows across Eastern IA
  - N-1-1 contingencies can overload 345 and 161 kV lines
  - 10 year out models show overloads for N-1
- Study Objectives:
  - Jointly evaluate reliability drivers
    - Limiting elements and affected generators shared between MISO and PJM
  - Determine whether projects can economically complement or replace proposed projects
    - 3 projects in Quad Cities targeted for Appendix B in MTEP15 (P8842-4)
    - Consider potential for interregional solutions
- Schedule: second half of 2015, time permitting
- Models, Analysis, IPSAC process parallels Michigan Interface analysis
- In addition to summer peak, add joint light load model for a more holistic look at congestion over the year
- Reliability and Market Efficiency analysis as appropriate

JOA Metrics and Processes

Overview

- Review stakeholder feedback provided since last meeting
- RTO Proposed Changes
- Tentative schedule
- Open discussion

Additional Feedback Since July Meeting

DATC

- Stands by all items in previously presented summary slide
- Priority for Interregional evaluation:
  - Reduce/remove $20M threshold
  - Reduce/remove 345 kV threshold
  - Upfront details on developer/builder selection from MISO
  - Third party review of costs for all projects being passed to regional process
  - Evaluate only in regional processes (no interregional approval)

Priority Ranking:

1. APC/NLP Split
2. B/C Ratio Requirement
3. Cost Threshold
4. Voltage Threshold

ITC

- Eliminate Cost Threshold
- Eliminate voltage threshold
- Reconsider B/C ratio threshold, along with further review of benefit definition/calculation
- Single, interregional evaluation of project
- Expand metrics used to define benefits (transfer capability, planning reserve margin, losses, M2M payments)

NIPSCO

NIPSCO reiterated previous, extensive feedback and priorities, and provided these additional priorities:

– Consider M2M *determination criteria* when selecting eligible flowgates for analysis

– *Consideration* should be given to pre-existing outages

NIPSCO

- There should be one interregional metric for CBMEPs (eliminate regional tests)
  - Projects 100 kV and above
  - Remove $20 million threshold
  - Metrics should capture short- and long-term costs including congestion relief, inter-RTO payments, and value of firm entitlements hedging against further inter-RTO payments
  - Models should be benchmarked against operations
- Eliminate/heavily reduce hedging assumptions in current NLP calculation
- Number of years that count toward NPV should be fixed, consistent with regional processes
- Reevaluate how new generation without signed IAs are sited
- Generation retirement study process should be formalized
- Incorporate interregional planning into regional planning cycles (timing-wise)

RTO Suggested Changes

RTO Proposal

- PJM and MISO propose, before the end of 2015, at a minimum
  - File changes to JOA to lower or eliminate the cost threshold for Interregional Market Efficiency Projects
  - Initiate regional stakeholder discussion of the MISO Tariff voltage threshold
  - Continue the IPSAC metric and process review aimed at additional reforms in 2015/2016
    - How metrics are calculated and how cost / benefit tests are performed

RTO Ideas on Metrics for Discussion

- Interregional Market Efficiency Project Benefits Calculation
  - Number and purpose of evaluations (this affects further metrics discussion)
    - Currently there is a single Interregional evaluation and two regional evaluations for project selection
    - Maintain or reduce the number?
    - Consider the purpose of the evaluation to include project selection and/or splitting the project costs
    - RTO comments:
      - Regional evaluations are necessary for regional project board approval
      - The regional evaluations ensure any project meets regional needs and criteria
      - Regional evaluations are necessary to ensure that most efficient or cost effective project is chosen
      - Interregional evaluation is necessary to split project costs between the RTO's
      - Interregional evaluations ensure proposals come forward that may address both regions' needs
      - Stakeholders can propose projects to meet interregional needs in both regions regardless of the interregional analysis result

RTO Ideas on Metrics for Discussion

- Interregional Market Efficiency Project Benefits Calculation
  - Number of analysis years
    - Perform a current year benchmark and quick hit analysis of current reliability and congestion issues
    - Analyze two additional years (+5 and +10)?
    - Use only analysis years or include interpolation / extrapolation?
    - RTO thoughts:
      - Current year model will eliminate need for extrapolation to current year.
      - The level of work should be streamlined. How many years are needed to meet purpose of the analysis?
      - How to determine out year benefits?

RTO Ideas on Metrics for Discussion

- APC/NLP
  - Consider impact of various metric changes, including APC/NLP split
  - Change weighting or eliminate one, add metric such as congestion quantification benefit?
  - RTO thoughts:
    - Should changes tend to metrics used in each region, or is it not necessary?
    - Should we consider an additional metric like congestion benefit. Sometimes different metrics can produce a different view of the "benefit"
    - Metrics based on LMP greatly magnify the benefit quantification (they are incremental costs and include congestion components)
    - Congestion netting is required in PJM regional metric
    - Netting congestion may reduce a project's benefit quantification but better quantifies cost savings for the native load

RTO Ideas on Metrics for Discussion

- APC/NLP (continued)
  - RTO thoughts
    - Production Cost Adjustments are necessary if changes in purchases and sales are modeled
    - Current adjustments are based on different incremental market values for purchasers and sellers so that the sum of adjusted production costs will not equal system production costs
    - The current adjustment can transfer more benefits to a purchaser than is received by a seller for the same amount of energy because of the different LMPs
    - Current adjustments change the production cost metric to be a combination of production cost and market values of energy transactions
    - Multiple pools very much complicates and adds confusion to the benefits calculation. Do we really want to approve a small project on the seam that is based on benefits of sales transactions between distant RTO neighbors? Do we want to approve projects far from the seam that supposedly produce “benefits” to both RTOs?

RTO Ideas on Metrics for Discussion

- B/C ratio requirement
  - Reduce or eliminate B/C ratio?
  - RTO thoughts:
    - This is tied to use of the calculation (cost splitting and/or project approval)
    - B/C may not be a high hurdle when other changes are implemented

RTO Ideas on Process for Discussion

- Timing between interregional and regional processes
  - Regional processes are robust but flexible to accommodate interaction with all of the RTO's interregional requirements.
  - Consider if changes to interregional process are needed to better align with regional ones
- Generation expansion and siting (EGEAS for MISO, queue inclusion for PJM) process
  - Assumptions rooted in regional processes
  - All assumptions must be reasonable for each regional process
  - Any expansion of existing capability must include transmission for deliverability
- Cost Review
  - Defer to regional evaluations. Are interregional cost evaluations needed?
- Improve modeling review/comment period
  - Is a long stakeholder review process necessary for both regional models and again when models are combined for an interregional review?
  - Models will be available in advance for stakeholder review
  - A process for necessary corrections

RTO Ideas on Annual Process for Discussion

- Annual process
  - Data and Identified Regional Needs and Plans exchange/review
  - Identify historical/current reliability and congestion and issues
  - Build Joint reliability and market efficiency current year models and benchmark
    - Even year detail, Odd year refresh
    - Goal is to sync the separate regional model builds on same joint power flow and power base release
    - Demonstrate reasonable benchmark models
    - Annual review of regional plans for consideration of interregional projects
    - Annual assessment of persistent congestion after planned topology upgrades added to other current year case assumptions
    - Consider targeted upgrades for cross border congestion

RTO Ideas on Proposal - Annual and Biennial Process

- Build joint 5 and 10 year models as needed in even years
  - Biennial analysis as needed – focus is upgrade benefit
  - Agree on joint assumptions to extent possible
  - Joint modeling of future years based on:
    - Extension of current year assumptions
    - Driven by expected conditions
  - Limit market efficiency footprint (PJM and MISO)
  - Controlled PJM/MISO transactions
  - Additional scenarios as necessary or as time permits
  - Joint reliability testing and scope (e.g. generation delivery)

Tentative Schedule

- August Webex- Review IPSAC Input & priorities for near term changes
  - PJM and MISO present “ideas” based on feedback so far.
- September Webex – Review and discussion as needed
- October - Reach consensus on first round of metric changes
- November – Work plan for 2016
- 4th quarter - RTO decision & filing

MISO Market Congestion Planning North-Central 2015 Update

Discussion

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Appendix A:
Summarized Stakeholder Feedback

MISO Environmental Sector

- Important
  - Reduce differences between interregional and regional planning processes Joint metrics still needed
    - Reduce $20M project cost threshold to $5M
    - Reduce MISO's regional voltage threshold from 345 kV to 100 kV (resolve through MISO's Regional Expansion Criteria and Benefits [RECB])
    - Perform next joint study in 2015 immediately after this process review ends
  - Achieve clarity and agreement on joint futures development process
    - Clarify upfront how futures will be used to evaluate and justify projects
    - Use multiple futures (if no agreement, MISO and PJM each pick one in addition to business-as-usual)
    - Use realistic state renewable portfolio standard levels
    - Include future modeling of Clean Power Plan

Hunt Power

- Important
  - Remove cost threshold
  - Align benefit years (same for all projects)
  - Focus on meaningful small or large projects on seam
  - Interregional study should be limited to only high impact projects
  - JOA metrics should be dealt with after critical seams congestion issues have been addressed
  - Examine West-to-East transfer capacity
  - Capacity import/export limits of ComEd, western MISO zones should inform process

- # Important
  - Joint metrics should include:
    - Reliability
    - Historic and future market efficiency
    - Public policy
    - Real-time operations
  - $20 million threshold is unnecessary
  - APC adjustments should be priced at LMP, not production cost
  - JOA metric calculation should be clearly understood by RTOs and succinctly explained to stakeholders
  - Interregional projects evaluated only through interregional process (remove regional studies for these projects)
  - Fully supports "quick fix" approach, should also consider larger projects to address quick fix needs
  - IPSAC should allow for stakeholder presentations
  - Encourage FERC to participate in IPSAC (ensure Order 1000 objectives met)
- # Unimportant
  - Whether joint metrics should be calculated

IURC

- Important
  - Support a one step process of joint interregional planning with its own metrics and voltage requirements
    - If this cannot be developed, need alignment of regional processes as much as possible
  - Joint metrics should capture short- and long-term benefits for projects 100 kV and above
    - Include inter-RTO payments
    - Benchmark against operations
    - Reduce/eliminate hedging assumptions to improve seams constraints
  - Reevaluate how new generation without signed interconnection agreements (IAs) are sited
  - Incorporate interregional planning into regional planning cycles (timing-wise)

DATC

- Important
  - Need upfront details on developer/builder selection (presentation and discussions necessary)
  - How JOA metrics are calculated should be easily replicated and capture relevant benefits
    - NLP should use generator- and load-weighted congestion components instead of RTO locational marginal prices
    - Propose a vote and relook at other options to current 70/30% adjusted production cost (APC)/net load payment (NLP) split
  - A presentation clearly explaining the process and assumptions used in a joint model should be provided prior to model release and feedback
    - This should be standardized and shared with stakeholders
- Unimportant
  - Regional planning differences are unimportant, were explained fairly well in previous round

AEP

- Important
  - Revise JOA process to align with FERC requirements
  - Align regional reliability monitoring and contingencies
  - Seam should be planned to respect both RTO criteria and tests
  - Upgrades should be based on most efficient and cost effect solutions, blind to location
  - Cost allocation based on avoided regional costs and independent regional benefits calculations (AEP has submitted detailed proposal on this)
  - Better explain process for interregional proposals and the alignment with regional processes
- Unimportant
  - Any effort to develop JOA metrics is unproductive, JOA rules will be superseded by regional rules

NIPSCO

- Important
  - There should be one interregional metric for CBMEPs (eliminate regional tests)
    - Projects 100 kV and above
    - Remove $20 million threshold
    - Metrics should capture short- and long-term costs including congestion relief, inter-RTO payments, and value of firm entitlements hedging against further inter-RTO payments
    - Models should be benchmarked against operations
  - Eliminate/heavily reduce hedging assumptions in current NLP calculation
  - Number of years that count toward NPV should be fixed, consistent with regional processes
  - Use escalation of benefits beyond final study year, rather than extrapolation
  - Reevaluate how new generation without signed IAs are sited
    - Reserve margins used in assumptions may not be appropriate

NIPSCO (cont.)

- Important (cont.)
  - Generation retirements and cost allocation methodology for upgrades is important
  - Create language specifying exactly how multiple futures will be considered and evaluated
  - Incorporate interregional planning into regional planning cycles (timing-wise)
    - Consistency of modeling assumptions and reliability criteria Alignment on GI process and dispatch assumptions
    - Reliability analysis should ensure that an RTO which prefers stricter reliability measures can maintain its preference
- Unimportant
  - Regional planning differences unimportant

- Important
  - Interregional-only modeling and screening process (eliminate regional processes)
    - Reduce $20M cost threshold to $5M
    - Develop formal controls process for models
    - Establish formal model review period
    - Adopt a single IPSAC model, assumptions
  - Clear process on how interregional projects are submitted
    - How cross-border construction activities are split and awarded
  - More alignment of interregional and regional approval timelines

- Important
  - Joint metrics Should continue to be used
  - No change on number, calculation

- Unimportant
  - Assumptions used in coordinated planning
  - Regional planning differences

Exelon

- Important
  - Improve processes and coordination
    - Interconnections and identification of cross border upgrades
    - Participant funded upgrades
    - Transmission service requests
    - Models, benchmarking, and error reduction
    - Align cycles, models, timelines
  - Eliminate provisional/conditional interconnections
  - Eliminate JOA metrics or align regional metrics
    - Remove $20M project cost threshold
  - One future scenario for consistency and certainty
  - No harm test on interregional projects to capture reliability costs
  - Third party review of interregional project costs

Appendix B: Summarized Issues List

Issues List - Metrics

- Reduce/remove $20M threshold (Environmental Sector, Hunt Power, ITC, IURC, MISO Developers, Exelon)
- Reduce/remove 345 kv threshold (Environmental Sector, Hunt Power, IURC, NIPSCO)
- Reduce/remove hedging assumption (IURC, NIPSCO)
- Reconsider 70/30 APC/NLP split (DATC, NIPSCO)
- Price APC adjustment with LMP rather than production cost (ITC)
- Align benefit years (same for all projects) (Hunt Power, NIPSCO)
- Use escalation of benefits beyond final study year, rather than extrapolation (NIPSCO)
- No Changes (FE)

Issues List – Process

- Improve coordination of interregional/regional study and approval timelines (IURC, AEP, NIPSCO, MISO Developers, Exelon)
- Evaluate only in interregional process – remove regional processes (ITCT, IURC, NIPSCO, MISO Developers)
- Evaluate only in regional processes (no interregional approval) (AEP, DATC, Exelon)
- Alignment of regional process metrics/ processes (IURC, NIPSCO, Exelon)
- Use a single model for interregional analysis (no multiple futures) (MISO Developers, Exelon)
- Develop formal model review period/process (DATC, MISO Developers, Exelon)
- Re-evaluate how speculative queue generation is included and sited (IURC, NIPSCO, Exelon)
- Metrics should consider inter-RTO payments (IURC, NIPSCO)
- Upfront details on developer/builder selection from MISO (DATC, MISO Developers)

Issues List – Process (Cont.)

- Clear Calculation method, explain details to stakeholders (ITCT, DATC)
- Specify how futures will be used (MISO Environmental Sector, NIPSCO)
- Use multiple futures (Environmental Sector)
- Model state RPS levels and Clean Power Plan requirements (Environmental Sector)
- Consider West to East transfer capability (Hunt Power)
- Consider capacity import/export limits (Hunt Power)
- Benchmarking process (IURC)
- No harm test to capture reliability costs (Exelon)
- Third party review of costs for all projects being passed to regional process (Exelon)
- Align regional reliability monitoring and contingencies (AEP)

Appendix C:
Existing Metric and Calculation

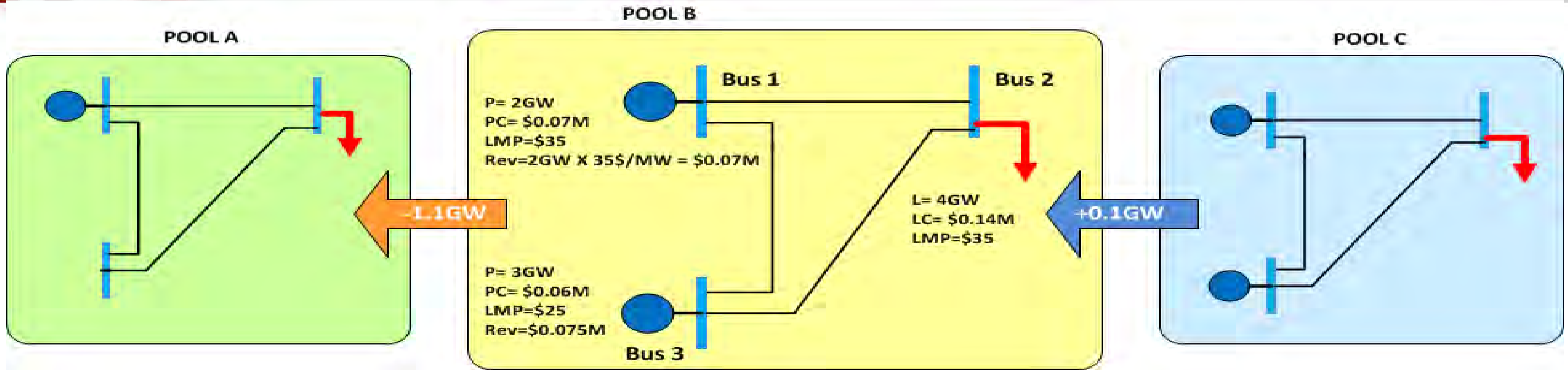
JOA - CBMEP Qualification

- **Projects must meet the following Criteria:**
  - Minimum project cost of $20 million or greater
  - Evaluated as part of a Coordinated System Plan or joint study process
  - Meet the benefit to cost ratio threshold 1.25 under JOA for Cross Border Market Efficiency Project (CBMEP)
    - Cross Border: 70% Adjusted Production Cost Savings (APCS) + 30% Net Load Payment Savings
    - Calculated over first 10 years of project life at a minimum
  - Meet the benefit to cost ratio threshold 1.25 under MISO tariff for MEP
    - MISO: 100% APCS over first 20 year of project life
  - Meet the benefit cost ratio threshold under PJM tariff for MEP
    - PJM: 70% Production Cost Savings + 30% Net Load Payment Savings over first 15 years of project life
  - Addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a Generation to Load Distribution Factor (GLDF) of 5% or greater with respect to serving load in that adjacent market

JOA Metric – Benefit Calculation

- JOA Benefit Metric = (70% of change in APC + 30% of change in NLP)
- Adjusted Production Cost (APC)
  - The APC for each RTO represents each RTO's production costs adjusted for interchange purchases and sales on an hourly basis.
  - Product costs include fuel cost, emission cost , O&M.
- Net Load Payments (NLP)
  - The NLP benefit for each RTO represents each RTO's gross load payment minus the estimated value of congestion-hedging transmission rights in each RTO.
- The JOA Benefit Metric will be calculated for each RTO for each year of simulation.
- Benefits for intermediate years between simulated years will be based on interpolation.
- The total project benefit will be determined by calculating the present value of annual benefits for, at a minimum, the first ten years of project life after the projected in-service year, with a maximum planning horizon of 20 years from the current year.

Benefit Calculation – APC For Single Hour (Example)



$$\mathbf{APC} = \mathbf{Pool\ Production\ Cost} + \mathbf{Purchases\ Cost} - \mathbf{Sales\ Rev.}$$

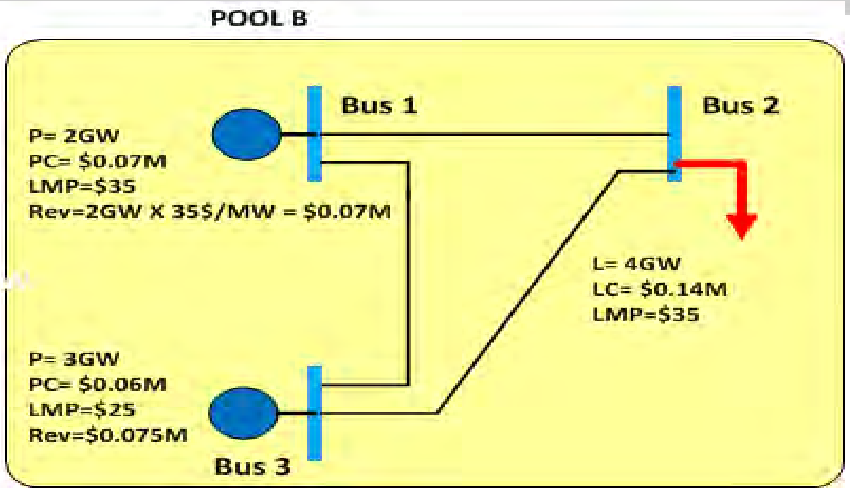
$$\text{Production Cost} = \$0.07M + \$0.06M = \$0.13M$$

$$\text{Purchases Cost} = Purchases \times Pool\ Load\ LMP$$
$$= 0.1GW \times 35\$/MW = \$0.004M$$

$$\text{Sales Revenue} = Sales \times Pool\ Gen\ LMP$$
$$= Sales \times Pool\ Gen\ Rev/Pool\ Gen$$
$$= 1.1GW \times (\$0.07M + \$0.075M)/(2GW + 3GW)$$
$$= 1.1GW \times 29\$/MW = \$0.03M$$

$$\mathbf{APC} = \$\mathbf{0.13}M + \$\mathbf{0.004}M - \$\mathbf{0.03M} = \$\mathbf{0.1M}$$

Benefit Calculation – NLP For Single Hour (Example)



$$\textbf{NLP} = \textbf{Gross Load Payment} - \textbf{Congestion Hedging}$$

$$\text{Gross Load } Payment = Load \times Pool\ Load\ LMP$$
$$= 4GW \times 35\$/MW = \$0.14M$$

$$\text{Congestion Hedging} = (Load\ LMP - Gen\ LMP) \times \min\{Gen\ MW, Load\ MW\}$$
$$= (35\$/MW - 29\$/MW) \times 4GW = \$0.024M$$

$$\textbf{NLP} = \$\mathbf{0.14}\boldsymbol{M} - \$\mathbf{0.024}\boldsymbol{M} = \$\mathbf{0.116M}$$

JOA Metric $= \mathbf{0.7}(\boldsymbol{APC}) + \mathbf{0.3}(\boldsymbol{NLP})$
$= \mathbf{0.7}(\$\mathbf{0.1}\boldsymbol{M}) + \mathbf{0.3}(\$\mathbf{0.12}\boldsymbol{M}) = \$\mathbf{0.11}\boldsymbol{M}$

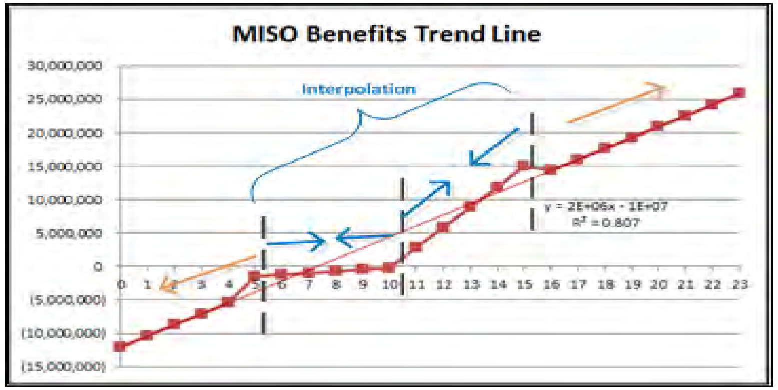
JOA Metric - Benefit Cost Ratio Calculation

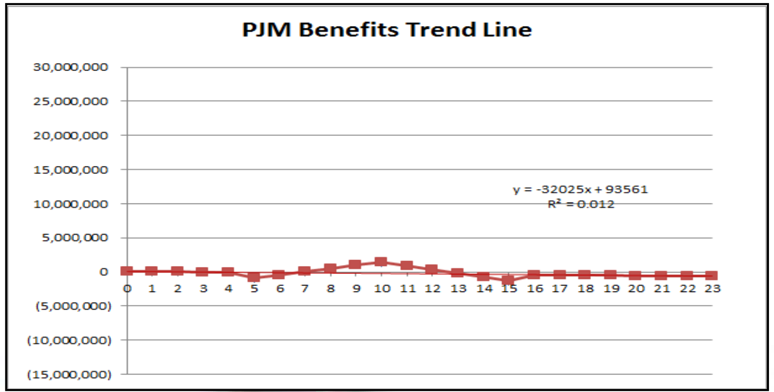
- **Benefits**
  - All benefits are calculated as the Net Present Value (NPV) of annual benefits for, at a minimum, the first 10 years of the project's life, with a maximum planning horizon of 20 years from the current year
  - Analysis are run to calculate the project's benefits for year 5, year 10 and year 15
  - Individual year values are interpolated or extrapolated to calculate the NPV.
- **Costs**
  - NPV of Capital Costs are calculated from the Annual Revenue Requirements of the project over the same period for which the project benefits are determined.

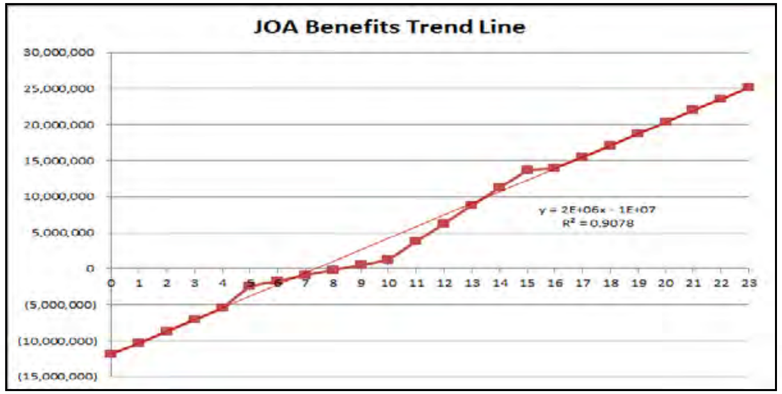
Benefit Calculation

- **Linear interpolation between the three study years.**
- **Trend Line (fit to the three study years) used for the years outside the study years**
- **Benefits calculated for each pool separately**

Year	Period	Annual Cost		MISO Metric Benefit	PJM Metric Benefit	JOA Metric Benefit
2013	1	$0		(12,028,241)	93,561	(11,934,680)
2014	2	$0	Trend Values	(10,382,405)	61,536	(10,320,869)
2015	3	$0		(8,736,569)	29,511	(8,707,058)
2016	4	$0		(7,090,733)	(2,514)	(7,093,248)
2017	5	$0		(5,444,897)	(34,539)	(5,479,437)
2018	6	$30,054,184	Simulated Value	(1,475,233)	(905,959)	(2,381,192)
2019	7	$30,054,184		(1,223,694)	(434,347)	(1,658,042)
2020	8	$30,054,184	Interpolated Values	(972,155)	37,264	(934,891)
2021	9	$30,054,184		(720,617)	508,875	(211,741)
2022	10	$30,054,184		(469,078)	980,487	511,409
2023	11	$30,054,184	Simulated Value	(217,539)	1,452,098	1,234,559
2024	12	$30,054,184		2,822,594	916,436	3,739,030
2025	13	$30,054,184	Interpolated Values	5,862,727	380,775	6,243,502
2026	14	$30,054,184		8,902,860	(154,887)	8,747,973
2027	15	$30,054,184		11,942,993	(690,548)	11,252,444
2028	16	$30,054,184	Simulated Value	14,983,126	(1,226,210)	13,756,916
2029	17	$30,054,184		14,305,133	(418,841)	13,886,292
2030	18	$30,054,184		15,950,969	(450,866)	15,500,103
2031	19	$30,054,184	Trend Values	17,596,805	(482,891)	17,113,913
2032	20	$30,054,184		19,242,641	(514,916)	18,727,724
2033	21	$30,054,184		20,888,477	(546,942)	20,341,535







Benefit Calculation

- JOA benefits are calculated as sum of the MISO benefits and PJM benefits.
- **NPV Assumptions:**
  - Inflation rate 2%
  - Discount Rate:
    - PJM: 7.7%
    - MISO: 8.1%
    - JOA Composite: 7.78%
  - Carrying Charge
    - PJM: 16.7%
    - MISO: 15.8%
    - JOA Composite: 16.25%
- **Time Horizon**
  - Using 10 years, starting with the in-service date.
  - Using a different time horizon may decrease/increase projected benefits

NPV Discount Rate	Period	Year	Annual Cost	Count for NPV?	MISO Metric Benefit	PJM Metric Benefit	JOA Metric Benefit
1	1	2013	$0	0	(12,028,241)	93,561	(11,934,680)
0.9278159	2	2014	$0	0	(9,632,961)	57,094	(9,575,867)
0.8608424	3	2015	$0	0	(7,520,809)	25,404	(7,495,405)
0.7987033	4	2016	$0	0	(5,663,392)	(2,008)	(5,665,400)
0.7410496	5	2017	$0	0	(4,034,939)	(25,595)	(4,060,535)
0.6875576	6	2018	$20,663,983	1	(1,014,308)	(622,899)	(1,637,207)
0.6379269	7	2019	$19,172,373	1	(780,627)	(277,082)	(1,057,709)
0.5918787	8	2020	$17,788,432	1	(575,398)	22,056	(553,342)
0.5491545	9	2021	$16,504,391	1	(395,730)	279,451	(116,279)
0.5095143	10	2022	$15,313,037	1	(239,002)	499,572	260,570
0.4727355	11	2023	$14,207,679	1	(102,838)	686,458	583,620
0.4386115	12	2024	$13,182,111	1	1,238,022	401,960	1,639,982
0.4069507	13	2025	$12,230,572	1	2,385,841	154,957	2,540,798
0.3775754	14	2026	$11,347,720	1	3,361,501	(58,481)	3,303,019
0.3503205	15	2027	$10,528,595	1	4,183,875	(241,913)	3,941,961
0.3250329	16	2028	$9,768,598	0	4,870,009	(398,559)	4,471,450
0.3015707	17	2029	$9,063,461	0	4,314,009	(126,310)	4,187,699
0.2798021	18	2030	$8,409,223	0	4,463,114	(126,153)	4,336,961

Project Description				JOA Benefit						MISO Benefit				PJM Benefit			
Project	Company	Cost	Expected ISD	2018 Benefit	2023 Benefit	2028 Benefit	JOA 10yr npv	JOA 10yr npv cost ($M)	JOA B/C Ratio	2018 Benefit	2023 Benefit	2028 Benefit	MISO 10Yr NPV	2018 Benefit	2023 Benefit	2028 Benefit	PJM 10yr npv
JOA13-PPL01-01	JOA	$ 163	2018	$ (2)	$ 1	$ 14	9.60	155.19	0.06	$ (1)	$ (0)	14.98	8.69	$ (1)	$ 1	(1.23)	0.91
JOA13-PPL02-01	JOA	$ 142	2018	$ (3)	$ (5)	$ (24)	(37.75)	135.20	-0.28	$ 8	$ 16	26.13	78.88	$ (10)	$ (21)	(50.19)	(116.63)

Note: Composite discount rate and carrying charge values are weighted averages of PJM and MISO values based on RTO capitalization.

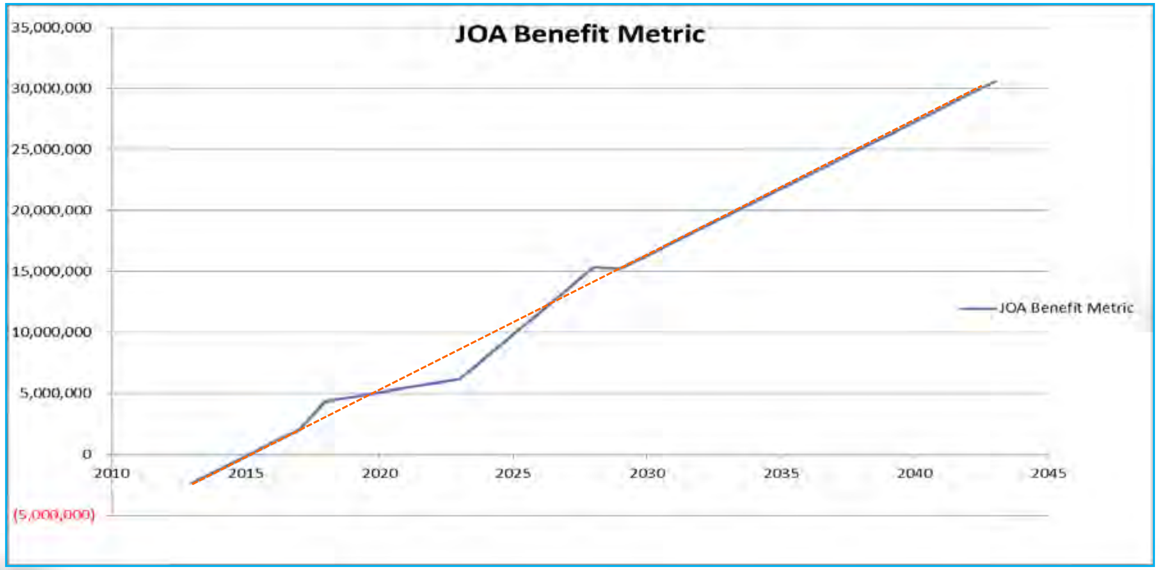
Benefit Calculation – JOA Metric Benefit For Multiple Years (Example)

Case	MISO					PJM					JOINT
	Prod. Cost ($M)	APC ($M)	Gross Load Pay. ($M)	NLP ($M)	JOA Metric ($M)	Prod. Cost ($M)	APC ($M)	Gross Load Pay. ($M)	NLP ($M)	JOA Metric (($M)	JOA Metric ($M)
Base Case 2018	23,018.4	21,781.2	36,125.7	33,970.7	**25,438.1**	24,777.8	25,360.2	47,512.3	44,558.2	**31,119.6**	**56,557.6**
Project Case 2018	23,016.0	21,781.9	36,111.5	33,959.7	**25,435.2**	24,779.0	25,359.9	47,506.3	44,553.8	**31,118.1**	**56,553.3**
Project Benefit 2018	2.4	**(0.7)**	14.2	**11.0**	**2.8**	(1.2)	0.3	6.0	**4.4**	**1.5**	**4.3**

0.7APC+ 0.3 NLP

MISO JOA Benefit + PJM JOA Benefit

Year	Source		JOA Joint Benefit
2013	Trend Values (trend line fit to three simulated values)		(2,375,160)
2014			(1,276,131)
2015			(177,102)
2016			921,927
2017			2,020,957
2018	Simulated Values		4,336,161
2019	Interpolated Values (linear interpolation from simulated values)		4,705,485
2020			5,074,809
2021			5,444,132
2022			5,813,456
2023	Simulated Values		6,182,780
2024	Interpolated Values		8,011,514
2025			9,840,249
2026			11,668,983
2027			13,497,717
2028	Simulated Values		15,326,452
2029	Trend Values		15,209,305
2030			16,308,334



Benefit Calculation – Cost and Benefit For Multiple Years (Example)

Benefit

1. Simulate 5,10,15 year out cases (2018,2023,2028)
2. Interpolate values for in between years:
   - Use 2018 and 2023 values for 2019-2022
3. Fit trend line around simulated values for all other years
   - Use trend line for years 2013-2017 and 2029 – 2032

Cost

1. Estimate provided in 2013 dollars: $30M
2. Cost inflated using 2% to estimated ISD of 2019
   - $\text{Inflated Cost} = \$30 \times (1 + 2\%)^{2019-2013} = \$33.8\text{M}$
3. Annualize project cost with fixed charge rate depending on RTO
   - $\text{Annual Cost} = \text{Inflated Cost} \times \text{Fixed Charge Rate}$
   - Fixed Charge Rate:
     - MISO: 15.8%
     - PJM: 16.7%
     - Joint Composite: 16.25%
   - $\text{Annual Cost} = \$33.8 \times 16.25\% = \$5.5\text{M}$

Benefit Calculation – Cost and Benefit For Multiple Years (Example)

B/C Ratio

1. Discount annual cost and benefit values to current year
   - $PV = FV \times (1 + Dicount\ Rate)^{-n}$
   - 2019 cost in 2013 dollars
     $PV = 5.5 \times 1.078^{-(2019-2013)}$
     $PV = 5.5 \times 0.64 = 3.5$
   - 2019 Benefit in 2013 dollars
     $PV = 4.7 \times 0.64 = 3.0$

2. Sum up costs and benefits for years which fall in a window:
   i. At least10years from expected ISD or great
   ii. No more than 20 years from current year

B/C Ratio = Total NPV Benefit / Cost
B/C Ratio = 1.73

Max 20 periods from current year

Min 10 periods from In Service Date

Year [1]	Count For NPV? [2]	Discount Factor [3]	Inflated Annual cost in future year adjusted by ARR [4]	Cost in current year [5]=[3]x[4]	Benefit in future year [6]	Benefit in current year [7]=[3]x[5]
2013	0	1.00				
2014	0	0.93				
2015	0	0.86				
2016	0	0.80				
2017	0	0.74				
2018	0	0.69				
2019	1	0.64	$5,490,042	$3,502,245	$4,705,485	$3,001,755
2020	1	0.59	$5,490,042	$3,249,439	$5,074,809	$3,003,671
2021	1	0.55	$5,490,042	$3,014,881	$5,444,132	$2,989,670
2022	1	0.51	$5,490,042	$2,797,255	$5,813,456	$2,962,039
2023	1	0.47	$5,490,042	$2,595,338	$6,182,780	$2,922,819
2024	1	0.44	$5,490,042	$2,407,996	$8,011,514	$3,513,942
2025	1	0.41	$5,490,042	$2,234,177	$9,840,249	$4,004,496
2026	1	0.38	$5,490,042	$2,072,905	$11,668,983	$4,405,921
2027	1	0.35	$5,490,042	$1,923,274	$13,497,717	$4,728,526
2028	1	0.33	$5,490,042	$1,784,444	$15,326,452	$4,981,601
2029	1	0.30	$5,490,042	$1,655,636	$15,209,305	$4,586,681
2030	1	0.28	$5,490,042	$1,536,125	$16,308,334	$4,563,106
2031	1	0.26	$5,490,042	$1,425,241	$17,407,363	$4,519,036
2032	1	0.24	$5,490,042	$1,322,362	$18,506,393	$4,457,551
2033	0	0.22	$5,490,042	$1,226,908	$19,605,422	$4,381,397
Total NPV Cost ($\sum([5] \times [2])$)				**$31,521,317**		
Total NPV Benefit ($\sum([7] \times [2])$)						**$54,640,816**