Energy and Reserve Pricing & Interchange Volatility
Final Proposal Report

October 8, 2014

[Energy and Reserve Pricing Problem Statement]
[Energy and Reserve Pricing Issue Charge]
Problem Statement brought forward by PJM
Problem Statement/Issue Charge approved at November 21, 2014 MRC
Number of Meetings covering this topic: 19

ENERGY AND RESERVE PRICING

Issue Summary

On peak days such as those experienced this past summer and winter, PJM operators schedule additional generation based on conditions that could reasonably materialize on the system. However, given the uncertainties that exist on such peak days such as load and interchange forecasts, all of the scheduled capacity on the system may not turn out to be economic and required to meet the demands on the system. When this occurs, the additional reserves created by generation commitments that turn out to be unneeded have the effect of reducing market prices. This produces prices which are counterintuitive given the operating conditions on a peak load day and do not reflect all of the actions taken by PJM's operators to maintain system reliability. In addition, the depressed prices contribute to the significant uplift payments that have become a focus of stakeholder concerns.

A short term solution was implemented for the summer 2014 period, with a sunset date of September 30, 2014. The group was tasked to provide a long term solution for the Energy and Reserve Pricing component of the issue charge as well as the Interchange Volatility component to carry through the winter 2015 period and going forward. The solutions for each component are independent of each other and will be voted on individually.

1. Energy and Reserve Pricing PJM Proposal

The PJM proposal for the Energy and Reserve Pricing component consists of A) changes to the calculation of the Day-Ahead Scheduling Reserves (DASR) requirement and DASR capability, B) changes to the commitment of long lead time resources in the Day-Ahead Energy Market and C) changes to the Real Time Reserves markets.

A) The PJM proposal offers changes to DASR in order to more accurately capture the additionally scheduled reserves that dispatchers have called on to be available in real time, as well as changes to more accurately assess and clear reserves. The proposal aims to use the economic max value of units instead of the emergency max value when calculating the DASR capability on individual resources. The purpose of this change is to align the way the market is cleared with the operational expectations of the resources, in recognition of the fact that in real time, absent a max gen emergency action, resources will only be dispatched up to economic max. In addition, the calculation of DASR capability of offline units will be changed to use the lesser of the unit's economic max or the unit's economic min plus its ramping capability in 30 minutes minus its start up and notification time. Currently, the calculation of capability from offline units does not factor in startup and notification time. This change aligns the calculation of DASR capability with the calculation of the capability of offline units in the non-synchronized reserve market. There are no proposed changes to the calculation of DASR capability of online units. DASR will cover the entire RTO only, with flexibility to implement a sub-zone if needed. The aforementioned changes will apply at all times rather than only in emergency conditions. However, during periods where a hot weather or cold weather alert or max emergency generation alert or other escalating emergency is in place, PJM proposes to increase the hourly DASR requirement by the amount of any additional reserves scheduled prior to the day-ahead market for the sole purpose of addressing operational uncertainty plus the difference between the hourly forecasted real time load and submitted fixed demand adjusted by a seasonal conditional demand factor. The seasonal conditional demand factor is calculated as the historical average of (Price Sensitive Demand + Decrement bids – Increment offers) divided by Fixed Demand during the peak hours for the top 10 peak load days in the same season the prior year. The cost allocation associated with these changes is two-fold. Charges for the base requirement (from the standard 6.27% of forecasted load) and any additional reserves for operational uncertainty will be allocated to real time load (this is the status quo allocation). Charges for the additional DASR requirement will be allocated to the differences between the day-ahead demand and real time load when the day-ahead demand is less than the real time load. In this calculation day-ahead demand is calculated as fixed demand + price sensitive demand + decrement bids – increment offers. If no LSEs underbid day-ahead demand compared to real time load, then the additional DASR requirement will be allocated to real time load.

B) In addition to changes in the DASR market, PJM proposes to make changes to the day-ahead commitment of long lead time units. Currently, if long lead time units are called on in advance of the day-ahead market, there is no guarantee that they will be picked up by the day-ahead market engine, especially if they do not change their start up and notification times. The proposal intends to commit these long lead time units scheduled by operators based on the schedule dictated by PJM operations. The trigger for committing these long lead time units in day-ahead is whenever long lead time resources have been scheduled and are still needed for the operating day. This change is not dependent upon the existence of emergency conditions.

C) In order to accurately capture additionally scheduled reserves in real time pricing, PJM proposes to increase the synchronized and primary reserve requirements during emergency conditions by the amount of any additional resources that have been intentionally scheduled for operational uncertainty after the Reliability Assurance Commitment (RAC) run. The emergency conditions that would trigger this action include hot weather or cold weather alerts, as well as max emergency generation alert, or other escalating emergency procedure. The extended reserve requirements would be calculated using the existing synchronized reserve and primary reserve requirements plus the sum of the additional intraday resources that have been committed for operational uncertainty. This additional amount should be between the sum of the resources economic min and economic max. This additional requirement would be implemented only during on peak hours, and only for the hours in which additional intraday resources are scheduled. The location for the requirement increase will depend on deliverability issues. If deliverability issues exist between the MAD location and the rest of the RTO, then the requirement will be increased for the zones or subzones in which the additional resources scheduled are located. For example, if additional resources are scheduled in the MAD subzone, then the requirement will increase for both the MAD and RTO locations. If the additionally scheduled resources are located in the non-MAD region, then only the RTO requirement would be increased. If there are no deliverability issues, then the requirement will be increased in RTO only. The additional requirement amount would be updated as needed and as additional intraday resources are scheduled and released. Members will be made aware of the increase in the requirement via a special notification message in the emergency procedures page, which triggers a message in eDATA, as well as a message in eMKT upon login. When this increased requirement is in effect, an additional step on the operating reserve demand curve will be implemented. The additional step will be set at a lower amount of $300 and will be used to price a shortage of the extended reserve requirements whenever the available reserves are insufficient to meet the extended reserve requirement, but still sufficient to meet the original reserve requirement. The additional step will require a change to the Operating Agreement and Open Access Transmission Tariff, and therefore FERC approval. The proposed changes to increase the reserve requirements will not involve any changes to how the settlements or allocations are calculated. All remaining rules surrounding the synchronized and primary reserve requirements will remain as status quo.

All proposed changes for the Energy and Reserve pricing solution are able to be implemented for the Winter 2015 period, with the exception of the DASR cost allocation and the additional step on the demand curve, which require tariff filings with FERC. The DASR cost allocation and demand curve changes will be implemented no later than Spring 2015.

2. Energy and Reserve Pricing MA Proposal

Monitoring Analytics (MA) offered an alternate proposal for the Energy and Reserve Pricing solution. While MA is overall supportive of PJM's proposal, they are proposing a change to the PJM proposal's treatment of the real time reserve requirements. Instead of increasing the reserve requirement for both synchronized and primary reserves under emergency conditions when additional intraday reserves have been scheduled to specifically account for operational uncertainty, MA proposes to increase the primary reserve requirement only. The rest of the MA proposal is the same as the PJM proposal.

3. Energy and Reserve Pricing Transition Proposal

An additional proposal was proposed by a stakeholder in an effort to combine the PJM and MA proposal and limit the impact to load until the alternative DASR cost allocation and the second lower step on the demand curve could be added. This transition proposal will implement the day-ahead unit commitment and the majority of the DASR requirement changes for Winter 2015 since PJM and MA are in agreement with those changes. However, the transition proposal suggests delaying the change to increase the DASR requirement by the difference between forecasted RT load and adjusted fixed demand under emergency procedures until the associated cost allocation change is approved by FERC. For the real time changes, the transition proposal implements the MA solution to only increase the primary reserve requirement until FERC approves the additional step on the synchronized and primary reserve demand curves. Once FERC approves the addition of the second step on the synchronized reserve and primary reserve demand curve, the PJM proposal to increase both the synchronized reserve and primary reserve requirements would then become effective.

4. Energy and Reserve Pricing Comparative Summary

As noted above, the main difference between the PJM and MA proposals for energy and reserve pricing is whether both the Synchronized Reserve and Primary Reserve requirements are updated when additional intraday reserves are scheduled for operational uncertainty or whether only the Primary Reserve requirement is updated. Monitoring

Analytics feels it is only necessary to update the Primary Reserve requirement because Synchronized Reserves are a subset of Primary Reserve and therefore the additional Primary Reserve requirement MW can be satisfied by the most economic mix of Synchronized Reserve and Primary Reserve and therefore the additional reserves procured by the clearing engines are not forced to be online reserves that can respond within 10 minutes. PJM believes it would be more appropriate to increase the synchronized reserve requirement, and consequently the primary reserve requirement since synchronized reserve is a subset of primary reserve, because the purpose of increasing the requirement is to better capture operator actions that have already been taken in energy and reserve pricing. The additional reserves that have already been called on by operators are online resources, synchronized reserves are more reflective of the service that is being provided by those reserves. Some stakeholders that are not supportive of increasing the synchronized reserve requirement noted that it is not guaranteed that an operator calling on 1 MW of additional reserve creates 1 additional MW of 10 minute synchronized reserve and therefore increasing the synchronized reserve requirement by the same amount may result in an over-procurement of reserves. In such cases, those stakeholders are more supportive of only increasing the primary reserve requirement because if we were unable to maintain the extended requirement, shortage pricing would only be applied to primary reserve, rather than potentially both synchronized reserve and primary reserve.

INTERCHANGE VOLATILITY

5. Interchange Volatility PJM Proposal

The PJM proposal for the Interchange Volatility component consists of implementing an hourly interchange cap for the forecasted peak hour(s) and surrounding hours during emergency conditions. The interchange cap will be used only when operators have made firm resource commitments and anticipated interchange schedules are sufficient to meet the projected load for the hour. The purpose of the interchange cap is to help ensure actual interchange more closely meets operators' expectations of interchange levels at the time they had to make decisions to call on additional CTs or demand response, for example, to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes; therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift. The interchange cap will typically be calculated and implemented 1-2 hours in advance of the operating hour. When in place, the interchange cap will limit the acceptance of spot import and hourly non-firm point to point interchange (imports and exports) not submitted as real time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly non-firm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap. The calculation of the interchange cap is based on the operator expectation of interchange for time T at the time the cap is calculated plus an additional margin. The margin is set at half of the largest contingency on the system, which is 700 MW. The additional margin also allows T-20 interchange to contribute to economically backfilling the loss of a unit or deviation between actual load and forecasted load. The interchange cap will be bound by the max sustainable interchange from PJM reliability studies. Communicating the interchange cap to members will be done via the ExSchedule banner notification plus a 'special notification' message in the emergency procedures page that will create an alert in eDATA. A notification of the potential of implementing the cap will be issued day-ahead, and a notification of the cap implementation will be made as soon as the cap is determined. The notification will include a MW amount and the hours in which the cap will apply. PJM's proposal also suggests changing the submission deadline for real time with price transactions from 12:00 day-ahead to 18:00 day-ahead.

Due to required software changes, the implementation of PJM's proposal will be in two phases. For the Winter 2015 period, any transactions violating the interchange cap will be manually curtailed. Operators will use a report highlighting hourly service that was scheduled after the implementation of the cap and will curtail hourly service above the cap on a last in/first out basis. In the spring of 2015, transactions violating the interchange cap will be automatically denied at the time of submission.

6. Interchange Volatility MA Proposal

Monitoring Analytics (MA) offered an alternate proposal for the Interchange Volatility solution. While MA is overall supportive of PJM's interchange volatility proposal, they are proposing several changes to the PJM proposal. Rather than calculating the interchange cap using PJM operators' expectation of the level of interchange for the time for which the cap will be effective (time T), MA proposes using only the transactions currently submitted in the ExSchedule application for time T and any real time with price transactions that have been submitted and are expected to clear. A 700 MW margin would still be added to that interchange value to arrive at the interchange cap value, similar to the PJM proposal. The second difference is related to the submission deadline for real time with price transactions. The MA proposal will allow real time with price transactions to be submitted up to 3 hours prior to the scheduled start time, rather than by 18:00 day ahead, and would reduce the min run time of such transactions from 1 hour to 15 minutes. The last difference is the implementation of additional market rules to prevent market manipulation with real time with price transactions. MA suggests that parallel rules should be applied to the interchange cap as are currently applied to ramp limits with regards to hoarding behaviors and manipulation. MA also suggests that price taking transactions not be allowed to be withdrawn and replaced by real time with price schedules by the same company or an affiliate after the interchange cap is set. Lastly, the same company or affiliate would not be allowed to simultaneously have a real time with price import and a price taking export. The rest of the MA interchange volatility proposal is the same as the PJM proposal.

7. Interchange Volatility Comparative Summary

The MA proposal suggests calculating the interchange cap using only the transactions that are currently submitted in ExSchedule for time T and real time with price transactions that are likely to clear as the base for the interchange cap prior to applying the 700 MW margin to arrive at the final cap value. The PJM proposal suggests using PJM operator's expectations of interchange instead. MA is concerned with the subjective nature of the expected interchange value and also would like to limit the submission of price taking transactions following the cap, while PJM feels it is necessary to align the cap with what operators are expecting will happen. PJM believes that limiting the cap to the transactions that are scheduled at the time the cap is put in place may result in operators having to call additional, more expensive CTs or DR to meet the cap instead of allowing an additional 1000 MW of interchange that is expected, but not yet scheduled, to be used to meet the peak load.

The second major difference is the submission deadline for real time with price transactions. PJM is changing the deadline from noon day-ahead to 18:00 day-ahead, coincident with the close of the re-bid period, in order to align the offer submission deadline of these transactions with that of generation resources. Monitoring Analytics suggests allowing these transactions to be allowed to submit offers up to 3 hours prior to the scheduled start time of the transaction. PJM is concerned this change will favor transactions backed by external generators over internal generation and would prefer to maintain comparability between the two resources. Monitoring Analytics does not view these transactions as being the same as internal generation and notes that emergency transactions are able to submit intraday offers and is therefore comfortable with the difference in offer submission timelines.

MA's proposal also includes additional transaction scheduling rules to prevent market manipulation through the use of real time with price transactions since these transactions would be allowed to be submitted up to 3 hours prior to the transaction start time. PJM does not feel that these additional rules are needed under the PJM proposal since the real time with price transaction submission deadline remains the day prior.

8. Standing Committee Results

This section will be updated with the results of voting at the October 8, 2014 meeting

Appendix I: Proposals Not Meeting the Threshold

There are no proposals that failed to meet the 3:2 threshold.

Appendix II: Supplemental Documents

ERPIV Long-term Proposal Matrix

M11 Revisions

M28 Revisions

Regional Practices Revisions

Appendix III: Stakeholder Participation

Last Name	First Name	Company Name	Sector
Ainspan	Malcolm	Energy Curtailment Specialists, Inc.	Other Supplier
Anders	David	PJM Interconnection, LLC	Not Applicable
Barker	Jason	Exelon Business Services Company, LLC	Transmission Owner
Benchek	Jim	FirstEnergy Solutions Corporation	Transmission Owner
Bernier	Luc	H.Q. Energy Services (U.S.), Inc.	Other Supplier
Bilash	Jason	PJM Interconnection, LLC	Not Applicable
Birnel	William	Westar Energy, Inc.	Other Supplier
Blair	Tom	Monitoring Analytics, LLC	Not Applicable
Bloom	David	Baltimore Gas and Electric Company	Transmission Owner
Bolan	Martin	FirstEnergy Solutions Corporation	Transmission Owner

Bonner (ES)	Charles	Dominion Virginia Power	Not Applicable
Borgatti	Mike	Gable and Associates	Not Applicable
Boyle	Glen	PJM Interconnection, LLC	Not Applicable
Brodbeck	John	Potomac Electric Power Company	Electric Distributor
Bryson	Mike	PJM Interconnection, LLC	Not Applicable
Campbell	Bruce	EnergyConnect, Inc.	Other Supplier
Canter	David	AEP	Transmission Owner
Carmean	Gregory	OPSI	Not Applicable
Carretta	Kenneth	PSEG Energy Resources and Trade LLC	Transmission Owner
Carroll	Rebecca	PJM Interconnection, LLC	Not Applicable
Ciabattoni	Joseph	PJM Interconnection, LLC	Not Applicable
Cicero	Nick	FirstEnergy Solutions Corporation	Transmission Owner
Citrolo	John	PSEG Energy Resources and Trade LLC	Transmission Owner
Coll	Daniel	PJM Interconnection, LLC	Not Applicable
Comeskey	Benjamin	Other	Not Applicable
Cox	Jason	Dynegy Marketing and Trade, LLC	Transmission Owner
Coyle	Billy	Dominion Virginia Power	Not Applicable
Coyne	Suzanne	PJM Interconnection, LLC	Not Applicable
Dadourian	John	Monitoring Analytics, LLC	Not Applicable
Dirani	Rami	PJM Interconnection, LLC	Not Applicable
Dugan	Bill	Customized Energy Solutions, Ltd.*	Not Applicable
Dugan	Chuck	East Kentucky Power Cooperative, Inc.	Transmission Owner
Dupeire	Michael	Ventyx	Not Applicable
Engle	Andrew	PJM Interconnection, LLC	Not Applicable
Erbrick	Michael	DhastCo,LLC	Not Applicable
Esposito	Pati	Atlantic Grid Operations A, LLC	Other Supplier
Etnoyer	Scott	Bayonne Plant Holding, L.L.C.	Generation Owner
Farber	John	DE Public Service Commission	Not Applicable
Fazio	Danielle	Noble Americas Gas & Power Corp.	Other Supplier
Fernandes	John	Other	Not Applicable
Fernandez	Ray	PJM Interconnection, LLC	Not Applicable
Filomena	Guy	Customized Energy Solutions, Ltd.*	Not Applicable
Fitch	Neal	NRG Power Marketing LLC	Generation Owner
Foladare	Kenneth	IMG Midstream LLC	Generation Owner
Frelich	Jessica	Integrys Energy Services, Inc.	Other Supplier
Galicia	Louis	Ventyx	Not Applicable
Gebolys	Debbie	Other	Not Applcable

Gell	Richard	Ontario Power Generation Inc.	Other Supplier
Gilani	Rehan	ConEdison Energy, Inc.	Other Supplier
Greening	Michele	PPL EnergyPlus, L.L.C.	Transmission Owner
Griffiths	Dan	Consumer Advocates of PJM States	Not Applcable
Grimes	Jordan	Other	Not Applicable
Hagaman	Derek	GT Power Group	Transmission Owner
Hastings	David	Cygnus Energy Futures, LLC	Other Supplier
Heizer	Fred	Ohio PUC	Not Applicable
Hendrzak	Chantal	PJM Interconnection, LLC	Not Applicable
Hoatson	Tom	Riverside Generating, LLC	Other Supplier
Horning	Lynn	PJM Interconnection, LLC	Not Applicable
Horstmann	John	Dayton Power & Light Company (The)	Transmission Owner
Hsia	Eric	PJM Interconnection, LLC	Not Applicable
Hubbard	Lance	Allegheny Electric Cooperative, Inc.	Electric Distributor
Hugee	Jacqulynn	PJM Interconnection, LLC	Not Applicable
Hyzinski	Tom	PPL EnergyPlus, L.L.C.	Transmission Owner
Jablonski	James	Borough of Butler, Butler Electric Division	Electric Distributor
Jennings	Kenneth	Duke Energy Business Services LLC	Generation Owner
Jett	William	Duke Energy Business Services LLC	Generation Owner
Johnson	Carl	Customized Energy Solutions, Ltd.*	Not Applicable
Keech	Adam	PJM Interconnection, LLC	Not Applicable
Kelly	Stephen	Brookfield Energy Marketing LP	Other Supplier
Kenney	Susan	PJM Interconnection, LLC	Not Applicable
Kochonies	Karen	Morgan Stanley Capital Group, Inc.	Other Supplier
Kogut	George	New York Power Authority	Other Supplier
Kormos	Mike	PJM Interconnection, LLC	Not Applicable
Lacy	Catharine	Dominion Virginia Power	Not Applicable
Leopold	Chris	Appalachian Power Company (APCO Dedicated)	None
Levine	Jeffrey	GDF Suez Retail Energy Solutions, LLC	Other Supplier
Li	Kanning	PJM Interconnection, LLC	Not Applicable
Lieberman	Steven	Old Dominion Electric Cooperative	Electric Distributor
Luna	Joel	Monitoring Analytics, LLC	Not Applicable
Ma	Alex	Bishop Hill Energy LLC	Generation Owner
Mabry	David	McNees Wallace & Nurick LLC	Not Applicable
Maher	Mollie	PPL EnergyPlus, L.L.C.	Transmission Owner

Mahoney	Julieanne	New York State Electric & Gas Corporation	Other Supplier
Marcino	Angelo	PJM Interconnection, LLC	Not Applicable
Mariam	Yohannes	Office of the Peoples Counsel for the District of Columbia	End User Customer
Marton	David	FirstEnergy Solutions Corporation	Transmission Owner
Mason	Mary	PJM Interconnection, LLC	Not Applicable
Matheson	Eric	Other	Not Applicable
Maucher	Andrea	Division of the Public Advocate of the State of Delaware	End User Customer
Maye	Shelly-Ann	North America Power Partners LLC	Other Supplier
McAlister	Lisa	American Municipal Power, Inc.	Electric Distributor
McLaughlin	Jeffrey	PJM Interconnection, LLC	Not Applicable
McNally	Stephen	Long Island Lighting Company d/b/a LIPA	Other Supplier
McNamara	Sean	PJM Interconnection, LLC	Not Applicable
Moerner	Lisa	Virginia Electric & Power Company	Transmission Owner
Monzon	Stephanie	PJM Interconnection, LLC	Not Applicable
Morelli	Lisa	PJM Interconnection, LLC	Not Applicable
Norton	Chris	American Municipal Power, Inc.	Electric Distributor
O'Connell	Robert	JPMorgan Ventures Energy Corporation	Other Supplier
Olaleye	Michael	PJM Interconnection, LLC	Not Applicable
Ondayko	Brock	Appalachain Power Company	Transmission Owner
Pacella	Chris	PJM Interconnection, LLC	Not Applicable
Pakela	Gregory	DTE Energy Trading, Inc.	Other Supplier
Park	Jinny	PJM Interconnection, LLC	Not Applicable
Parker	Seth	Long Island Lighting Company dba LIPA	Other Supplier
Patel	Keyur	PJM Interconnection, LLC	Not Applicable
Patten	Kevin	Appalachain Power Company	Transmission Owner
Peoples	John	Duquesne Light Company	Transmission Owner
Philips	Marjorie	Hess Corporation	Other Supplier
Pilong	Chris	PJM Interconnection, LLC	Not Applicable
Plante	Matthieu	H.Q. Energy Services (U.S.), Inc.	Other Supplier
Pratzon	David	GT Power Group	Not Applicable
Rajan (ES)	Abhijit	Dominion Resources	Not Applicable
Reichert	Joshua	Other	None
Rohrbach	John	Southern Maryland Electric Cooperative	Electric Distributor
Rokholt	Thomas	EnerNOC, Inc.	Other Supplier
Rolashevich	Pete	FERC	Not Applicable
Rushing	Joe	PJM Interconnection, LLC	Not Applicable

Saini	Ishwar	Macquarie Energy LLC	Other Supplier
Scarpignato	Dave	Direct Energy Business, LLC	Other Supplier
Shanker	Roy	H.Q. Energy Services (U.S.), Inc.	Other Supplier
Shparber	Steve	PJM Interconnection, LLC	Not Applicable
Slade	Louis	Virginia Electric & Power Company	Transmission Owner
Snow	Robert	The Federal Energy Regulatory Commission	Not Applicable
Sock	Bryan	PSEG Energy Resources and Trade LLC	Transmission Owner
Souder	Rich	PJM Interconnection, LLC	Not Applicable
Stadelmeyer	Rebecca	Exelon Business Services Company, LLC	Transmission Owner
Steele	Alison	Encentiv Energy	Not Applicable
Suh	Jung	Noble Americas Energy Solutions LLC	Other Supplier
Terry	Jonathan	Allegheny Electric Cooperative, Inc.	Electric Distributor
Velasco	Cheryl Mae	PJM Interconnection, LLC	Not Applicable
Wadsworth	Joseph	Vitol Inc.	Other Supplier
Ward	Mike	PJM Interconnection, LLC	Not Applicable
Warshel	Kim	PJM Interconnection, LLC	Not Applicable
Weathers	Brian	PJM Interconnection, LLC	Not Applicable
Wharton	Matt	PJM Interconnection, LLC	Not Applicable
Wilhite	Chad	FirstEnergy Solutions Corp.	Transmission Owner
Williams	Michael	Black Oak Energy, LLC	Other Supplier
Williams	Stan	PJM Interconnection, LLC	Not Applicable
Wisersky	Megan	Madison Gas & Electric	Other Supplier