UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.	))))	Docket No. ER10-713-002

COMMENTS AND MOTION FOR TECHNICAL CONFERENCE OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rules 211 and 212 of the Commission's Rules and Regulations, 18 CFR §§ 385.211 & 385.212 (2010), Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"),[1] submits these comments on and motion for a technical conference to further consider the compliance filing submitted by PJM Interconnection, L.L.C. ("PJM") and Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC") on June 28, 2010 ("June 28th Filing") in response to the Commission's directives in its order of May 28, 2010.[2] In the May 28th Order the Commission conditionally approved the PJM/PEC Joint Operating Agreement ("JOA") filed in this proceeding subject to the condition that PJM/PEC provide further information addressing a number of concerns.[3] The PJM/PEC responses to those concerns validate the

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1 Capitalized terms used herein and not otherwise defined have the meaning provide in the PJM Open Access Transmission Tariff.

2 *PJM Interconnection, L.L.C.*, 131 FERC ¶61,181 (2010) ("May 28th Order").

3 *Id*. at 4.

Market Monitor's earlier criticism of the JOA for singling out PEC for special treatment at the expense of movement forward to create a comprehensive approach to seams at PJM's southern boundary that is just, reasonable and not discriminatory.

Because, as explained in detail below, PJM/PEC have failed to provide an adequate response to any of the Commission's questions and this proceeding raises complicated technical issues about how to address pricing at RTO seams, the Market Monitor motions for the Commission to institute a technical conference to ensure the issues raised by the JOA are fully vetted.

I. COMMENTS

The Commission's inquiries about whether the PJM/PEC JOA is discriminatory as a result of provisions permitting PEC to acquire transmission after the fact, enjoy favorable treatment of make whole payments, and exclude nuclear and hydro units from the Carolina export pricing point calculation deserved clear and direct responses. Instead, PJM/PEC contort the definition of a dynamic schedule throughout their response in an attempt mask to how the business rules they are proposing are inequitable to existing energy transactions and inconsistent with market logic. However, the PJM/PEC responses provide no justification for PEC to receive the benefits of treatment as internal PJM generation without also incurring the obligations of internal PJM generation. If the Commission agrees that PJM/PEC have failed to satisfy the Commission's concerns, then it should condition its approval of the excision of those aspects of the PJM/PEC JOA that are discriminatory and fail to produce accurate, just and reasonable calculations of prices at the PJM/PEC interface.

PJM/PEC explain (at 3) their approach as follows:

> … Carolina Power has committed to follow a 5-minute PJM price signal and, as such, [the "dynamic schedule"] behaves more like internal generation following PJM dispatch than a normal, block-scheduled transaction. That is, it will behave more like internal PJM generation, responding to price signals to manage constraints on the PJM/Carolina path (and nearby facilities) and, as such, provides an efficient constraint management process which utilizes market influences to dictate enhanced reliability.

The explanation further states (at 3), "The real time PJM/Carolina dynamic schedule will be included in the [Available Flowgate Capability] AFC calculation as expected generator output (day-ahead) and then managed in real-time to support existing transmission commitments and the reservations will be posted on the PJM OASIS node after the fact for transparency."

The PJM/PEC explanation summarizes one of the central issues with the proposed treatment of the dynamic schedule. PEC wants the benefits of the treatment accorded to PJM internal generation without incurring the associated obligations. The dynamic schedule approach does not impose the same requirements on PEC as are imposed on all generators within PJM. For example, the PJM/PEC JOA does not require PEC to submit a day-ahead schedule, nor does it require the payment of operating reserve charges as the PJM tariff requires for all other generators participating in the PJM Interchange Energy Market. The PJM/PEC JOA confers all of the benefits of being in the PJM market without the risks. This preferential treatment compared to internal PJM generation resources results in an unjust and unreasonable economic incentive for PEC to remain outside of the organized wholesale markets. This weakens PJM and similar institutions by depriving them of the ability to demonstrate the merits of membership that are consistent with beneficial public policy.[4]

A. After the Fact Transmission Reservations are Not Consistent with NERC Reliability Standards (Response to Question No. 1).

The PJM/PEC JOA includes provisions for acquiring after the fact transmission reservations for the dynamic schedule. Acquisition of transmission after the fact is not compliant with an open access approach to transmission as required under Order No. 888, et seq.,[5] nor does it ensure that transfer capabilities are held within calculated limits. The PJM/Carolina response argues (at 3) that since the dynamic schedule responds to real-time

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[4] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶61,126 (2009).

[5] *See*, *e.g.*, Statement of Chairman Joseph T. Kelliher, Seams Issues for RTOs and ISOs in the Eastern Interconnection, Docket No. AD06-9-000 (March 29, 2007) (" The Commission's policy promotes voluntary RTO formation. I personally support voluntary RTO formation, and our competition review is focused in large part on reforms to improve RTO markets. However, if RTO membership is voluntary, then members must have some ability to withdraw. Our order in Louisville Gas & Electric Company shows that we honor contractual withdrawal rights. However, our policies should not provide an incentive to RTO members to withdraw and we must examine ways to address the issues associated with non-members who use RTO markets.")

market signals, acquisition of after the fact transmission reservations is appropriate. Order No. 888 offers no precedent for permitting after the fact reservations under similar circumstances. Consequently, the PJM/PEC dynamic schedule should not be granted the preferential access to transmission after the fact.

Requirement R1.2 of the current NERC Standard (Interchange Standard INT-006-2) states "Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated." The purpose of this standard is "To ensure that each Arranged Interchange is checked for reliability before it is implemented." PJM/PEC reference the Dynamic Transfer White Paper developed by NERC in their response to justify how after the fact transmission reservations are consistent with NERC reliability standards. The NERC Interchange Subcommittee created the Dynamic Transfer White Paper in 2003 to provide guidance to the industry on the requirements for implementing a dynamic transfer. Work on the document ceased upon completion of draft version 4, so the White Paper does not reflect current NERC reliability standards (as can be seen by the various references to the replaced NERC policy 3 throughout the document). Consequently, the Commission should rely on references to the Dynamic Transfer White Paper with caution.

PJM/PEC argue (at 4) that "the generation contemplated by the PJM/Carolina schedule is included as actual interchange in the ACE equation consistent with the guidance provided to the industry in the Dynamic Transfer White Paper issued by NERC."

Regardless of how the PJM/PEC dynamic schedule is modeled in the respective Energy Management Systems (EMS) (i.e. as scheduled or actual interchange, or as a dynamic schedule or pseudo tie) the Dynamic Transfer White Paper requires transmission reservations in advance of the implementation of the transfer of energy. The Dynamic Transfer White Paper states (emphasis added):

> A. All Dynamic Schedules used to move the control of generation, loads or resources from one Control Area to another must meet the following requirements:
>
> **2. Transmission Service**
>
> > **2.1** <u>Prior to implementation of the Dynamic Transfer of load or generation</u>, it is the obligation of each involved CONTROL AREA to assure that the Dynamic Transfer is implemented such that the tariff requirements of the applicable TRANSMISSION PROVIDER(S) are met, including applicable ancillary services and provision of losses.
> >
> > **2.2** If transmission service between the SOURCE and SINK CONTROL AREAS is curtailed then the allowable range of the magnitude of the schedules between them, including DYNAMIC SCHEDULES, may have to be limited.[6] And;
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> B. All Pseudo-Ties used to move generation, loads or resources from the Native Control Area to the Attaining Control Area must meet the following requirements:
>
> **2. Transmission Service**
>
> > **2.1.** <u>Prior to implementation of the Dynamic Transfer of load or generation</u>, it is the obligation of each involved CONTROL AREA to assure that the Dynamic Transfer is implemented such that the tariff requirements of the applicable TRANSMISSION PROVIDER(S) are met, including applicable ancillary services and provision of losses.[7]

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[6] Dynamic Transfer White Paper at 3

[7] Dynamic Transfer White Paper at 5.

> **2.2.** If transmission service between the Native and Attaining Control Areas is curtailed then the allowable range of the magnitude of the PSEUDO-TIES between them must be limited to these constraints. And;

Appendix B.

> **5. Scheduling of Transmission**
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> Transmission must be procured sufficient to cover the potential capacity range of the Dynamic Transfer Signal. All transmission necessary to deliver the energy must be reserved and scheduled with the Native, Attaining and Contract Intermediary Control Areas according to the applicable requirements specified in Policy 3.[8] And;
>
> **13. Transmission Reservation**
>
> Amounts of Firm Transmission sufficient to deliver the entire potential bi-directional demand must be reserved throughout the contract path.[9]

PJM/PEC also argue (at 4) that because the dynamic schedule is following PJM dispatch signals, there is no reason to require an advance transmission reservation. However, this is inconsistent with PJM's past practice. This dynamic schedule is analogous to the PJM/ComEd Pathway transaction that was implemented during the interim stages of the PJM market growth initiatives in 2004 in that it also followed PJM dispatch, and was used to control for constraints and to provide a least cost economic dispatch. Although the Pathway dynamic transfer spanned a balancing authority that was not party to the dispatch (i.e. AEP), transmission sufficient to deliver the entire potential demand was required, in advance, for the portions of the path into and out of both ComEd and PJM. The Pathway

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8 Dynamic Transfer White Paper at 9.

9 Dynamic Transfer White Paper at 11.

dynamic transfer also responded to PJM dispatch signals, and this transfer necessitated the procurement of transmission service in advance of the transfer of energy. No preferential access to transmission reserved after the fact was required or provided.

B. It Is Not Appropriate to Allow After the Fact Transmission Reservations to Accommodate the Dynamic Schedule to Some, but Not All, PJM Market Participants (Response to Question No. 2).

The preferential treatment for after the fact reservations proposed for the PJM/PEC dynamic schedule relies on the assumption that the power flow will be in the direction that will alleviate constraints on the PJM transmission system, thus available transfer capability will always be available after the fact. This ignores the fact that any transaction flowing against the constraint also alleviates congestion on the transmission system, yet other transactions are not permitted to make reservations after the fact. All other market participants must assume the risks of acquiring transmission in advance, not knowing at the time of reservation if they will be able to use the reservation or not. The preferential treatment of after the fact transmission offered to Carolina Power is unwarranted, unjustified and only provides economical benefits that other market participants are not offered.

PJM/Carolina claims (at 4) that:

> … [T]he PJM/Carolina transactions are contemplated as actual interchanges, as opposed to scheduled interchanges, and such actual interchanges do not require reservations. Thus, the PJM/Carolina agreement to record after the fact reservations actually exceeds established requirements and provides increased transparency compared to similar dynamic energy transfers, such as pseudo-ties.

The argument that actual interchanges do not need to acquire transmission service in advance of energy transfers again contradicts the Dynamic Transfer White Paper. The Dynamic Transfer White Paper clearly explains (at 3, 5, 9 & 11) not only that dynamic transfers require transmission in advance, but that dispatchers must treat dynamic transfers like all other transactions during TLRs or other transmission service curtailments. PJM/PEC's treatment of the dynamic schedule as actual interchange does not change the requirement for acquiring transmission in advance, nor is it a basis for any preferential treatment. Additionally, all other dynamic schedules and pseudo ties implemented in the PJM Market include a requirement that the party receiving such service acquire transmission in advance, and those parties did not receive preferential access to after the fact reservations despite being modeled as actual interchange in the EMS.

C. Interchange Is Impacted in Instances Where ATC is Unavailable After the Fact (Response to Question No. 3).

The purpose of calculating available transfer capability (ATC) is to ensure that adequate transfer reserve and capacity benefit margins are met before allocating the balance for market participants to utilize in support of external transactions. The physics of the transmission system will dictate whether the transaction could flow in real time, but those physics do not account for margins that ensure reliable transmission operations. In other words, just because a transaction flowed in real-time, it does not mean that those flows were consistent with reliability standards or would have been permitted under reliability standards. Allowing for after the fact transmission reservations violates the premise on which ATC is calculated.

PJM/PEC state (at 5) that a reservation must be requested and approved, in advance, on the Carolina Power side, to use the dynamic schedule. To the extent that ATC is unavailable, then the dynamic schedule will be capped at the reservation amount on the Carolina Power transmission system. This argument highlights the fact that PEC units will respond to price signals based solely on PJM transmission constraints, even though ATC must also account for constraints on the PEC system, and raises the question as to how effective a Congestion Management Agreement (CMA) can be if it considers only constraints in one balancing authority. The CMA should account for constraints on all parties' systems and price the resulting dispatch of generation to account for the relief of all constraints. That PEC does not operate an energy market is no reason why the CMA cannot capture and account for the effects of PEC's generation, on both PEC and PJM constraints. The CMA can still provide for the determination of a security constrained, least cost generation mix for the combined PJM and Carolina Power regions, creating the most economical approach to reliably supply load in the broader region.

PJM/PEC also argue (at 5) that the dynamic schedule will relieve transmission constraints; and, therefore, consistently increase ATC available for market participants to reserve on the PJM system. Additionally, the AFC calculation will include the PJM/PEC schedule as expected generator output where it can be managed in real-time to support existing transmission commitments. PJM/PEC state (at 5) that "the minute-to-minute changes in transfer will always be in the direction that relieves PJM transmission constraints." However, this minute to minute response would not provide adequate timing for other market participants to take advantage of the increase in ATC, as transmission must be reserved in advance. Additionally, without the requirement for the dynamic schedule to be submitted in the Day-Ahead Energy Market, as is required by all internal PJM generation, the forecasted benefits obtained by the ATC would not be included in the PJM calculation where it could benefit other market participants. Finally, even if other market participants were to be able to take advantage of the newly "created" ATC, PJM/PEC do not adequately explain what would happen if no ATC is available on the PJM system after the fact, as other market participants would have utilized the ATC "created" by the dynamic schedule, again reducing ATC to zero. For example, if there were no ATC available for an export transaction from PJM at a given time, and the dynamic schedule "created" an additional 50 MW of ATC for that time that a third party utilized, the ATC would again be reduced to zero for that time period, leaving no ATC available after the fact for the PJM/PEC dynamic schedule.

D. The Transfer Capability Used to Support the Dynamic Schedule Is Not Consistent with Actual Interchange (Response to Question No. 4(a)).

PJM/PEC state (at 5), "The transfer capability used to support the interchange is handled consistently as an actual interchange. The reservations are done after the fact (for purposes of verification) and not included in the ACE calculation, similar to internal generation dispatch." Market transparency requires posting, in advance, of reservations on the PJM Open Access Same-Time Information System (OASIS). Posting a reservation after the fact is inconsistent with the purpose of OASIS.

PJM/PEC assert that the dynamic schedule is similar to internal generation dispatch and should receive the transfer capability benefits of internal PJM generation. If PEC is to be treated as internal PJM generation, PEC generation should actually be treated like all other internal generation, including requirements applicable for deliverability of export transactions, associated financial support for the transmission system and any necessary enhancements to that system. The PJM/PEC dynamic schedule makes no such provisions; therefore, the dynamic schedule's interchange should not be treated on a par with internal PJM dispatch with regards to the use of the transfer capability.

Additionally, PJM/PEC contradict the Dynamic Transfer White Paper when they state (at 5), "The transfer capability used to support the interchange is handled consistently as an actual interchange." The requirements set forth in that document require the advance acquisition of transmission to implement a dynamic transfer of energy, and offer no provisions for after the fact reservations.

E. The Proposed Methodology for Managing the Dynamic Schedule Does Not Guarantee That ATC Will Be Available After the Fact (Response to Question No. 4(b)).

PJM/PEC claim (at 6) that "the expected PJM/Carolina transactions will be included in the AFC calculation as expected generator output and then managed in real-time to support existing transmission commitments." If PJM has the ability to include an estimate of expected generator output that can be used to accurately and reliably calculate AFC, that same estimate could be used as the basis on which Carolina Power could acquire transmission in advance. PJM/PEC do not explain why their argument should not be extended to require transmission reservations in advance. Also, while the [Unit Dispatch System] UDS calculation may be more representative of actual system conditions, and will include the ramping capability of the dynamic schedule, the case may exist where the ramping capability may limit the amount of relief that the schedule can provide on a constraint, thus exceeding the ATC limits for a period of time.

For example, assume PEC exports 500 MW to PJM at a period of time when a constraint occurs that would require the dynamic schedule to change direction to a PJM export. The proposed ramping limit for the dynamic schedule of 50 MW in five minutes would mean that the dynamic schedule would be flowing against the constraint for almost an entire hour while ramping down to change direction. During that period of time, if there was originally zero ATC available for the import, other than that "created" by the dynamic schedule, there would be no additional relief provided by the dynamic schedule. On the contrary, the schedule would be temporarily continuing to hurt the constraint, leaving no ATC available to reserve after the fact.

F. PEC Dispatch Is Affected by Excluding Nuclear and Hydro Units From the Interface Price Calculation (Response to Question No. 5(a)).

PJM/PEC claim (at 6), "The intent of the interface pricing calculation [eliminating hydro and nuclear units from the calculation] associated with the PJM/Carolina congestion management agreement is to price the energy transfer between PJM and Carolina Power based on the units that are actually moving to support the energy transfer." The intent of the interface pricing calculation should not be based on the definition as provided by PJM/PEC; rather, the calculation should be based on setting the appropriate price to reflect the effects of PEC generation on constraints and thereby elicit an appropriate response. That is the basis of locational marginal pricing ("LMP"), and nothing in the PJM/PEC JOA justifies its modification.

To fully understand the effects on PEC dispatch that the elimination of a particular unit has on the interface pricing point, it is important to first understand how the interface price is determined. The JOA proposes the use of the Marginal Cost Proxy Method for the determination of the interface price (with the caveat of eliminating nuclear and hydro units from the calculation). The Marginal Cost Proxy Method requires the submittal of generator cost data to PJM. This pricing method is based on the incremental production cost of the marginal generator of the external supplier. The marginal generator is based on the incremental production cost to supply load in the external area, supported by real-time metered output data. For imports to PJM, if the LMP at the unit, calculated by PJM with reference to PJM generation and load, is greater than or equal to the production cost for each unit on line, then the interface price is equal to the PJM calculated bus LMP of the marginal unit. If the LMP is less than the production cost for any unit on line, then the interface price is equal to the lowest PJM calculated LMP of any such units. For exports from PJM, if the LMP is greater than or equal to the production cost for each unit on line, then the interface price is equal to the PJM calculated LMP of the marginal production unit.

If the LMP is greater than the production cost for any unit on line, then the interface price is equal to the highest PJM calculated LMP of any such unit.

Below are two examples of this methodology's export LMP pricing calculation. The first describes the scenario where the LMPs at the respective buses are less than the production cost of all generators in the neighboring balancing authority. The second describes the scenario where at least one LMP is greater than the production cost of the generator at its bus.

Example 1:

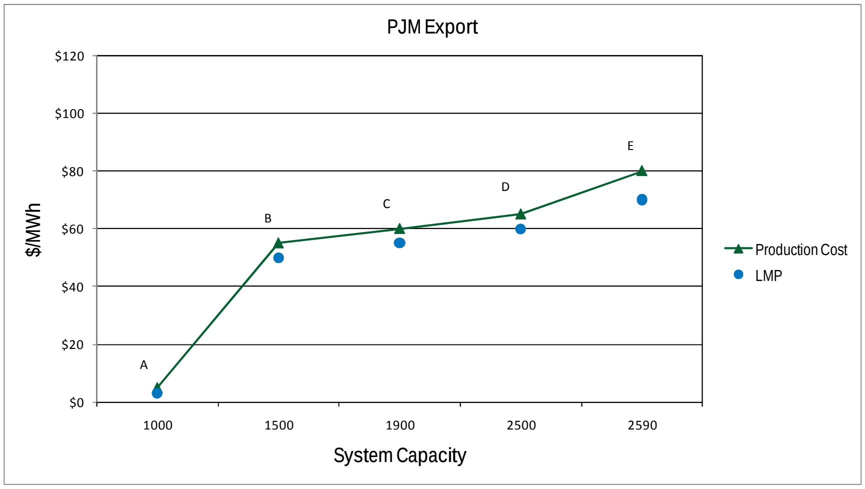
Table 1 below shows the sample characteristics of the units, as well as existing PJM calculated LMPs for the example.

Table 1 Example plant characteristics and PJM calculated LMP

Plant	Capacity (MW)	System Capacity (MW)	Production Cost	LMP
A	1000	1000	$5	$3
B	500	1500	$55	$50
C	400	1900	$60	$55
D	600	2500	$65	$60
E	90	2590	$80	$70

Using the data provided, the unit production cost curve can be created, as shown in Figure 1 below.

Figure 1 Unit production cost curve



Assume that the current generation on-line in the Carolina Power Balancing Authority is 2,590 MW. Using the data provided, and analyzing the unit production cost curve, it can be determined that the PJM calculated LMP is lower than the production cost of all units. The Marginal Cost Proxy Method identifies unit E as the marginal unit, thus the interface price would be set to the PJM calculated LMP at unit E, or $70.

Example 2:

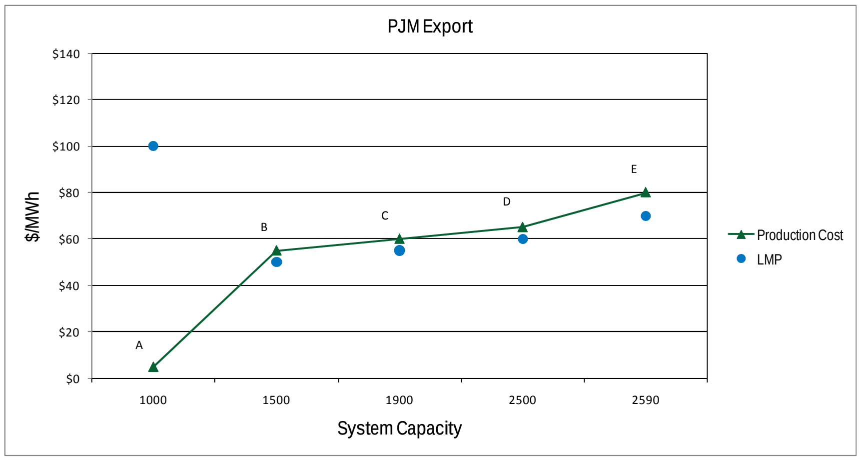
Table 2 below shows the sample characteristics of the units, as well as existing PJM calculated LMPs for the second example.

Table 2 Example plant characteristics and PJM calculated LMP

Plant	Capacity (MW)	System Capacity (MW)	Production Cost	LMP
A	1000	1000	$5	$100
B	500	1500	$55	$50
C	400	1900	$60	$55
D	600	2500	$65	$60
E	90	2590	$80	$70

Using the data provided, the unit production cost curve can be created, as shown in Figure 2 below.

Figure 2 Unit production cost curve



Assume that the current generation on-line in the Carolina Power Balancing Authority is 2,590 MW. Using the data provided, and analyzing the unit production cost curve, it can be determined that the PJM calculated LMP is lower than the production cost of all units, with the exception of unit A. The Marginal Cost Proxy Method defines the interface price as the PJM calculated LMP at unit A, or $100, because it fails the LMP versus production cost test.

PJM/PEC provide an example in an attempt to explain how the exclusion of non dispatchable units (i.e. nuclear and hydro units) provides for an appropriate response by PEC generation. The data PJM/PEC use in their example is shown in Table 3 below. Their example illustrates how, if a non dispatchable generator (generator "A") is the only unit where the calculated LMP is greater than the marginal cost of the unit, the interface price would be set at that unit's LMP ($120), and would not set a price that would incent PEC generation to move. However, by excluding the non dispatchable unit, the interface price would be determined based on the PJM calculated LMP of the marginal unit (Unit E), or $70. This interface price, determined based on the remaining generation, would therefore incent Carolina Power to reduce the output of their highest cost unit (Unit E) and purchase power from PJM.

Table 3 Example plant characteristics and PJM calculated LMP as provided by PJM.

Plant	Capacity (MW)	System Capacity (MW)	Production Cost	LMP
A	1000	1000	$5	$120
B	500	1500	$55	$50
C	400	1900	$60	$55
D	600	2500	$65	$60
E	90	2590	$80	$70

There are two main issues with the example PJM/PEC provide. First, the dispatchability or lack of dispatchability of a unit is irrelevant to the problem created by this methodology. The same problem would result if all the units in question were flexible and dispatchable. For example, the same problem would occur if the only unit where the PJM calculated LMP is greater than the production cost were a dispatchable unit, as opposed to a non dispatchable unit as PJM/PEC outline. Given the unit characteristics and LMPs as shown in Table 4 below, where unit A is still the only non dispatchable unit, the interface price would be set to the PJM calculated LMP at unit B, or $120, as it is the only unit that fails the production cost versus LMP test. As in the PJM/PEC example, PEC would not be incented to move generation. So, whether the unit that is setting the interface price is dispatchable or non dispatchable is irrelevant to the effects of PEC's dispatch. It is not acceptable to ignore the dispatchable unit in the calculation of the interface price, nor is it acceptable to ignore the non dispatchable units in the calculation, as the effects on PEC's response would be the same.

Table 4 Example plant characteristics and PJM calculated LMP

Plant	Capacity (MW)	System Capacity (MW)	Production Cost	LMP
A	1000	1000	$5	$3
B	500	1500	$55	$120
C	400	1900	$60	$55
D	600	2500	$65	$60
E	90	2590	$80	$70

The second issue with the example that PJM/PEC provide is that excluding the non dispatchable unit from the calculation can limit the amount of relief that PEC could provide to a constraint in certain circumstances. The example data that PJM/PEC provide (as shown in Table 3 above) shows how the interface price, including the non dispatchable unit in the determination, would be set to $120, and would not elicit a response from PEC generation. However, by eliminating the non dispatchable unit from the calculation, the interface price would be set to $70, thus incenting PEC to reduce the generation of unit E. While this response encourages the appropriate response, it effectively sets 90 MW as the maximum amount of relief that PEC would expect to provide (the total output of unit E), as unit D's marginal cost (the next highest marginal cost unit) of $65 would be lower than the interface price and would not respond. To illustrate further, consider the unit characteristics and

LMP data as shown in Table 5 below. This is the same data as provided in the PJM/PEC example, with the exception of the PJM calculated LMP of $10 at the non dispatchable unit (unit A) as opposed to the $120 used in the PJM/PEC example.

Table 5 Example plant characteristics and PJM calculated LMP

Plant	Capacity (MW)	System Capacity (MW)	Production Cost	LMP
A	1000	1000	$5	~~$120~~ $10
B	500	1500	$55	$50
C	400	1900	$60	$55
D	600	2500	$65	$60
E	90	2590	$80	$70

In this example, the EXPORT interface price would be set at $10/MWh (as opposed to $120 in the PJM/PEC example), as this is still the only calculated LMP that is above the marginal cost. The effect of including the non dispatchable unit in this example would be to incent PEC to reduce the generation of units B, C, D and E, as the interface price would be below the marginal cost of all of those units. In the PJM/PEC example, had PJM excluded the non-dispatchable unit, the EXPORT interface price would have been set to $70, thus only incenting unit E to reduce generation, as that would be the only unit where the interface price is below the marginal cost of the unit. In this example, by excluding the non dispatchable unit, PEC is incented to limit the potential relief they are capable of providing, as only one unit would reduce generation.

G. Excluding PEC's Nuclear and Hydro Units from the Calculation of Export Prices Will Not Incent PEC Generation to Back Down in Order to Receive an Export from PJM (Response to Question No. 5(b)).

The examples above illustrate that the exclusion of Carolina Power's non dispatchable units (i.e. nuclear and hydro units) from the calculation of export prices would not consistently provide the proper incentive for Carolina Power's plants to back down. The examples also explain why the price signal is inaccurate when excluding PEC's nuclear and hydro units. As in all other implementations of LMP, the calculation of the interface prices should include these units.

H. Reserving Generation for Native Load Obligations Is Inconsistent with the Basis on Which an LMP Market Is Designed (Response to Question No. 5(c)).

The PJM/PEC response argues (at 6) that hydro units are not dispatchable as their output is for "[PEC's] retail native load obligations in North and South Carolina." The mere fact that PEC can reserve output for their own purposes illustrates the inconsistency of the PEC approach to interface pricing with locational marginal pricing. LMPs reflect the actual incremental cost to generate power to meet actual loads. LMP calculations do not and should not account for the designation of certain MWh for certain customers. Failing to offer all available generation to the interface price calculation would have an effect similar to economic withholding in a market and prices would be affected.

Also, by claiming that the output is for PEC's native load obligations, PJM/PEC is making the argument that they can control the physics of the system to direct the output of those units specifically for retail native load. Not only is this impossible; it is contrary to the basis on which an LMP market is designed, where the prices reflect the value of the energy at the specific location and time it is delivered. PJM's "*locational pricing fact sheet*" states, "The calculations factor in **<u>all</u>** the available generating sources to come up with the mix that creates the lowest production cost, while observing all limits on the transmission system" (emphasis added),[10] providing no exceptions for excluding resources that are earmarked to serve specific load within the market.

I. The Carolina Import and Export Pricing Points Should Be Available to Third-Party Participants (Response to Question No. 6).

PJM/PEC respond (at 7) that:

> The Carolina import and export pricing points will be applied to all transactions equally. That is, all transactions sourcing in the Carolina Power Balancing Authority and sinking in PJM will receive either the Carolina Power import price or the SOUTHIMP price equally, depending on the outcome of the required checks. The same is true for all other transactions sourcing in PJM and sinking in Carolina Power with respect to the Carolina Power export or SOUTHEXP prices.

Third party market participants should understand however, that the actions of Carolina Power affect the LMP paid (or received) from PJM in those instances. In other words, a market participant may be expecting to receive the Carolina Power import price in a particular hour; however, Carolina Power may accept an import transaction into the Carolina Power Balancing Authority from yet another market participant, effectively

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10 *See* PJM, "*Locational Marginal Pricing Fact Sheet*." (March 26, 2010) (Accessed July 8, 2010) <*http://www.pjm.com/~/media/about-pjm/newsroom/downloads/locational-marginal-pricing-fact-sheet.ashx*> (105 Kb).

causing the interface price for that hour to revert to the SOUTHIMP interface price, which all parties will be subject to.

Additionally, the Market Monitor agrees with the requested clarification made by the North Carolina Electric Membership Corporation (NCEMC) with regards to allowing a sub-area within Carolina Power's balancing authority area to elect an interface pricing method that is different than the method elected by Carolina Power.[11] It was not the Market Monitor's intent to prevent alternative methods of congestion management by requesting clarification that third parties have access to the Carolina Power import and export prices.

J. The Export Make Whole Payments Can Impact Other Market Participants' Revenues (Response to Question No. 7).

The make whole payments are intended to compensate PEC for any money lost as a result of helping alleviate PJM constraints in the instances where the dynamic schedule switches direction within an hour. This can occur due to the hourly integration of PJM's five-minute LMPs. These make whole payments will be applied to the import and export portions of the dynamic schedule where, for the import portion, PJM will calculate the total revenue earned by PEC for each hour, and summing for all hours of the calendar day. PJM will also calculate the PEC cost of providing the import transaction for each hour, and summing all hours of the calendar day. If the total cost exceeds the total revenue for all hours of the calendar day, PJM will make PEC whole through Balancing Operating

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[11] Request for Clarification, or in the Alternative for Rehearing, of North Carolina Electric Membership Corporation filed in Docket No. ER10-713-000 ({DATE}).

Reserves. For the export portion, PJM will calculate the total cost incurred by PEC for each hour, and summing for all hours of the calendar day. PJM will also calculate PEC's avoided cost of receiving the export transaction each hour, and summing for the calendar day. If the total cost incurred by PEC exceeds the total avoided cost for the calendar day, PJM will make PEC whole for the difference through Balancing Operating Reserves.

The Market Monitor recommended that the Commission reject the export portion of the make whole payments to be consistent with the way PJM treats other export transactions. PJM does not currently have make whole provisions for export transactions, and PJM's "*Operating Agreement Accounting*" manual even explicitly excludes dynamically scheduled exports from their calculations.[12] PJM/PEC note (at 7) that "there will be no additional impact of this arrangement beyond the impacts already observed due to make whole payments to other resources on the PJM system." Creating a make whole payment specifically for PEC's export transaction is granting preferential treatment, and affects the pool of Balancing Operating Reserves that can be allocated to other market participants. Carolina Power should not receive this preferential treatment in the collection of operating reserves that contribute to those impacts already observed.

The PJM/PEC answer also attempts to justify the dynamic transfer make whole payments and does not adequately quantify the impact for not granting make whole payments to other participants' export transactions. This is an important distinction, as the

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funding for the make whole payments will source from operating reserves. However, operating reserves are not collected from export transactions, so the allocation of make whole payments could potentially increase the operating reserve charges to all other market participants to fund the make whole payments. Granting make whole payments for the export portion of the dynamic schedule creates another example of preferential treatment granted to PEC in the JOA.

K. The Eight 5-Minute Periods in an Hour Used for Determining Make Whole Payment Eligibility Is Not Based on Any Existing Precedent Nor Is It Consistent with PJM Internal Generation Requirements (Response to Question No. 8(a)).

The PJM/PEC answer states (at 8) that, "Because PJM does not dispatch Carolina Power's generators similar to the way that it dispatches internal generators, PJM cannot use the Ramp-limited desired MW calculation that is used for internal generators." This statement, on its own, contradicts the arguments that PJM/PEC make when arguing that the dynamic schedule should be treated similar to that of an internal generator. PJM/PEC shift the definition of the dynamic schedule within the JOA and in subsequent filings supporting the JOA, in an attempt to best fit existing business rules to their desired outcome in each context. PJM/PEC should state whether the dynamic schedule should be treated as an internal generator, to which all relevant PJM business rules would apply, or not, to which other business rules would apply. In either case, application of the rules should not discriminate among different parties. Additionally, the PJM/PEC answer states (at 8) that "there is no absolute precedent for the use of the 'eight 5-minute periods in an hour' criterion to qualify Carolina Power for make whole payments." They further state (at 8) that "the "eight 5-minute periods in an hour" was crafted as a reasonable and defined metric that would provide a sufficient measure of determining whether Carolina Power is following PJM LMP signals, without imposing an unrealistic and overly burdensome requirement that it follow that price signal perfectly." The PJM/PEC response does not quantify how the eight 5-minute periods within an hour compare to the requirements of the ramp limited desired calculation (which internal PJM resources are measured against), nor do they qualify how their choice of the eight 5-minute periods within an hour reasonable.

PJM/PEC also state (at 8) that "it is unreasonable to require Carolina Power to follow dispatch perfectly for the hour to qualify for make whole payments when internal generators are not required to do so either." The Market Monitor does not oppose applying a bandwidth within which the dynamic schedule must follow the PJM dispatch signal in qualifying for make whole payments, so long as the same metrics are applied to all market participants. Section 14.5.3 of the JOA explains the proposed bandwidth, which the Market Monitor finds consistent with the requirements for internal generation as outlined in the PJM Tariff. However, the PJM tariff applies the bandwidth for the entire hour, not eight 5-minute periods within the hour. Requiring Carolina Power to follow dispatch, within the specified bandwidth, for the entire hour does not require that Carolina Power follow dispatch "perfectly", it merely imposes the same requirement on Carolina Power as applies to internal PJM resources.

L. Not Requiring Carolina Power to Follow the PJM Dispatch Signal for All Intervals within an Hour Does Not Hold Carolina Power to a Higher Standard than Internal PJM Generation (Response to Question No. 8(b)).

The PJM/PEC response states (at 8):

> PJM does not hold its own internal generators, which it explicitly dispatches, to that stringent of a standard; but they are expected to do so within an acceptable bandwidth (which, generally speaking, is based upon a time weighted average over the course of an hour). Holding Carolina Power to a higher standard than is required for internal generators are unreasonable and fails to provide the proper incentives for Carolina Power to respond appropriately.

Section 14 of the JOA defines the acceptable bandwidth for which the PJM/PEC dynamic schedule will be determined for following dispatch within a 5-minute interval. This bandwidth is similar to that of the ramp limited desired bandwidth of internal PJM generators. It would not be holding the PJM/PEC dynamic schedule to a "higher standard" to require it to remain within the bandwidth in all 5-minute intervals in an hour to qualify for make whole payments, as there is no less of a requirement for internal generation following a ramp limited desired signal. The requirement to follow the dispatch signal in all 5-minute intervals is not unreasonable, nor would it fail to provide the proper incentive for Carolina Power to respond appropriately.

M. Make Whole Payments Should Not Be Granted to Carolina Power When the Interface Price Reverts to The Default SOUTHIMP/SOUTHEXP Price (Response to Question No. 8(c)).

If Carolina Power is exporting power at the same time they are importing from PJM, or if they are importing power at the same time they are exporting to PJM, the interface price associated to the dynamic schedule will revert to the SOUTHIMP/SOUTHEXP default interface price. The PJM/PEC response states that even when the interface price reverts to the default pricing point, PEC would remain eligible to receive make whole payments for responding to the PJM pricing signal.

The Market Monitor strongly disagrees with the PJM/PEC response that would allow PEC to remain eligible to receive make whole payments if the price reverts to the SOUTHIMP/SOUTHEXP price. The intent of the CMA is to incent PEC to respond to PJM price signals to assist in the control for transmission constraints. If PEC chooses to export the energy it is receiving from PJM to another balancing authority, the effect would be that a wheeling transaction would be created, and generation within the Carolina Power Balancing Authority would not change. Similarly, if PEC chooses to import energy from another balancing authority at the same time it is exporting to PJM, this too creates a wheeling transaction through PEC, and generation within the Carolina Power Balancing Authority would not change. Under these circumstances, the benefits obtained from the redispatch of PEC's generation on transmission constraints would not be realized, and therefore, PEC should not be made whole when the interface price reverts to the SOUTHIMP/SOUTHEXP price.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford these comments due consideration and grant the Market Monitor's motion for a technical conference as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: July 19, 2010

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 19th day of July, 2010.

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