UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc.	**)** **)**	**Docket No. ER11-1844-000**

PROTEST OF THE
NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

In accordance with Rule 211 of the Commission's Rules of Practice and Procedure[1] and with the Commission's November 4, 2010 *Notice of Extension of Time*, the New York Independent System Operator, Inc. ("NYISO") respectfully submits this Protest against the application of Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") and International Transmission Company d/b/a ITC Transmission ("ITC") proposing revisions to the Midwest ISO's tariffs "to allocate and recover the cost of the ITC Phase Angle Regulating Transformers at Bunce Creek on the Michigan-Ontario border among the Midwest ISO, [NYISO], and PJM Interconnection, L.L.C. ("PJM")."[2] In this Protest the NYISO refers to the joint Midwest ISO/ITC pleading as the "Application" and to the Midwest ISO and ITC collectively as the "Applicants."

The Application seeks to impose costs associated with Phase Angle Regulators that ITC has constructed at its Bunce Creek station on a transmission line connecting Michigan and Ontario ("Replacement PARs") on ratepayers in New York and PJM. The Replacement PARs would replace an earlier PAR that failed shortly after it was placed in-service in 2003. The activation and effective operation of the Replacement PARs would restore control functionality that was supposed to have been in place for at least the last seven years, and that was expected to provide substantial benefits to Detroit Edison Company's ("Detroit Edison's") and ITC's

[1] 18 CFR Part 35.

[2] Application at 1.

Michigan customers. For the reasons set forth below, the cost allocation sought by the Applicants is unprecedented, unjustified, and would be unjust and unreasonable. The Applicants' request should therefore be rejected.

I. Executive Summary

The Commission should reject the Applicants' *ex post* proposal to allocate the cost of transmission facilities that ITC has been in the process of constructing since 2006[3] to consumers in New York. The Application is patently deficient and inconsistent with Commission precedent for numerous reasons including, but not limited to, the following:

A. The Cost Allocation Proposal Is Not Consistent With Commission Precedent

- <u>"Postage Stamp" Versus "License Plate" Rate Design</u>. Under a postage-stamp rate design, the costs of transmission facilities are spread broadly among identified beneficiaries of those facilities, including customers in geographic areas outside of the zone where the facilities are located.[4] By contrast, "[u]nder a license-plate (or zonal) rate design, a customer pays the embedded cost of transmission facilities that are located in the same zone as the customer. A customer does not pay for other transmission facilities outside of the zone, even if the customer engages in transactions that rely on those zones."[5]
    - As explained below, the Midwest ISO Board of Directors has approved recovery of the cost of the Replacement PARs from ITC's customers under a license plate rate within the Midwest ISO footprint. The Application does not propose to disturb the use of a license plate cost recovery mechanism within the Midwest ISO. Instead the Application proposes to recover approximately half of the cost of constructing and operating the Replacement PARs from ratepayers in New York and PJM, using what amounts to an unprecedented, multi-regional, postage stamp rate.

- <u>The Commission Has Repeatedly Rejected Proposals to Adopt Postage Stamp Rates for Existing Facilities</u>. For the entire seven year period that the Replacement PARs have been in development, the Commission's policy has been to allocate the costs of existing

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[3] *See Request of ITC to Amend Presidential Permit,* submitted to the United States Department of Energy ("DOE") in Docket No. PP-230-3 at 5 (2009). Available on the DOE's web site at:

http://www.oe.energy.gov/DocumentsandMedia/230-4_ap.pdf

[4] *See American Electric Power Service Corp. v. Midwest Independent Transmission System Operator, Inc., et al.*, 125 FERC ¶ 61,341 at n.10 (2008).

[5] *PJM Interconnection, L.L.C.*, 130 FERC ¶ 61,052 at n.3 (2010).

transmission facilities to the relevant transmission owner's customers, even though, in many cases, such facilities provide benefits to ratepayers in other geographic locations. This policy is founded on equitable considerations and concern for economic and administrative efficiency. The Commission has repeatedly rejected efforts by transmission developers to reallocate costs of existing transmission facilities, such as the Replacement PARs, through the use of "postage stamp rates," and has required instead that the costs of such facilities continue to be recovered through "license plate rates" from the transmission owner's customers.[6]

- The Commission Has Previously Rejected *Ex Post* Efforts to Reallocate Sunk Transmission Costs. In the limited instances in which the Commission has permitted transmission costs to be allocated broadly to designated beneficiaries *within* a given region, the Commission has been careful to place constraints on the applicability of such mechanisms. The Commission has only permitted the use of postage stamp rates on a prospective basis, where the facilities to which such postage stamp rates apply are constructed *after* the rates are accepted by the Commission.[7] Postage stamp rates are not available for existing facilities that were constructed prior to the establishment of the rate. Furthermore, the Commission has repeatedly insisted that postage stamp rates apply only to facilities that are planned pursuant to an organized, regional process in which *all* ratepayers who might have to bear the costs of such facilities have both (1) notice that they might be expected to pay for such facilities, and (2) an opportunity to participate fully in the planning of such facilities.[8]

- The Replacement PARs Are Existing Facilities for Which Postage Stamp Rates Are Not Available. The Commission has made clear that where a transmission developer has proceeded to undertake substantial planning or construction of transmission facilities under a license plate rate mechanism – as ITC has done here – it will not be permitted later to reallocate the costs of those facilities on a postage stamp basis.[9] Given that ITC's facilities were planned and constructed under a license plate rate mechanism, the after-the-fact, expanded cost allocation now sought by Applicants is prohibited.

- ITC Planned and Constructed the Original Bunce Creek Par and the Replacement PARs for the Benefit of its Ratepayers, and to Satisfy Michigan's Retail Access Statute; Not to Provide Broader Regional Benefits. The history of the Bunce Creek PARs, as evidenced by public statements by ITC and its predecessor-in-interest, Detroit Edison, highlights that the original Bunce Creek PAR was constructed to benefit ITC's ratepayers, and to satisfy requirements of Michigan's retail access statute. The benefits to ITC ratepayers included the control of parallel path flows between Michigan and Ontario, and the

[6] *See American Electric Power Service Corp. v. Midwest Independent Transmission System Operator, Inc., et al.*, 122 FERC ¶ 61,083 at P 31, *order on rehearing*, 125 FERC ¶ 61,341 (2008); *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063 (2007), *order on reh'g*, Opinion No. 494-A, 122 FERC P 61,082 (2008).

[7] *See* Opinion No. 494, 119 FERC ¶ 61,063 at P 53.

[8] *See American Electric Power Service Corp. v. Midwest Independent Transmission System Operator, Inc., et al.*, 122 FERC ¶ 61,083 at P 99.

[9] *See* Opinion No. 494, 119 FERC ¶ 61,063 at P 53.

increase of transmission capacity in Michigan. Statements made by ITC *before* it embarked on its attempt to re-allocate the cost of the Replacement PARs to New York ratepayers make clear that the Replacement PARs are intended to serve the same purposes as the original Bunce Creek PAR. ITC did not seek authority to recover the cost of constructing or operating the original Bunce Creek PAR from New York.

- <u>The Replacement PARs Were Not Planned and Constructed in Accordance With the Kind of Regional Process That Is A Prerequisite to Regional Cost Allocation</u>. To the extent that the NYISO and New York ratepayers have had any discussions with ITC, the Midwest ISO, or any other entity regarding the Replacement PARs, those discussions have been informal communications, largely at the operational (as opposed to joint system planning) level, and have not been part of the type of formalized, regional planning process that is a prerequisite to the cost allocation sought by the Applicants.[10] Neither the NYISO nor New York ratepayers have been brought into, or been asked to participate in, the design, planning, or installation process for the Replacement PARs, and have had absolutely no say over the nature or amount of the PARs expenditures incurred by ITC. Applicants cannot demonstrate that either the original Bunce Creek PAR, or the Replacement PARs were the subject of a regional planning process that included the New York ratepayers that they propose to allocate a portion of the cost of the Replacement PARs to in the Application.

    - The draft Replacement PAR operating documents that the Midwest ISO submitted to the Department of Energy,[11] proposed Attachment SS-1 to the Midwest ISO's tariff, and a recently rejected Midwest ISO proposal addressing how the Replacement PARs should be modeled in the NERC Interchange Distribution Calculator ("IDC") to determine available Transmission Line Loading Relief,[12] provide additional evidence that the Midwest ISO and ITC have not involved the NYISO in their planning efforts. Each of the identified documents contain provisions that favor ITC and Midwest ISO interests and/or do not provide for similar consideration of New York interests. If ITC and the Midwest ISO had involved the NYISO in the preparation of these documents, the documents would be more even-handed in their treatment of New York.

- <u>None of the Decisions Cited In The Application Authorize *Ex Post* Cost Allocation To Non-Customers Located In Other Regions</u>. Applicants cite a number of Commission and court decisions in the hope that at least one of the cases they cite will resonate with the Commission. None of the cases cited support the Applicants' request. For example,

[10] In the 1998-1999 timeframe studies were apparently performed to ensure that the operation of the Ontario/Michigan PARs, including the original Bunce Creek PAR, would not significantly harm neighboring systems.

[11] The "Operating Instructions" that the Midwest ISO proposed to the Department of Energy in Docket No. PP-230-4 are included as an attachment to Attachment A to this Protest.

[12] Both the Midwest ISO's presentation to the IDC Working Group and the NYISO's responsive presentation raising its concerns with the Midwest ISO's proposal are included as Attachments B and C to this Protest. The IDC Working Group did not approve the Midwest ISO's proposed method of modeling the Ontario/Michigan PARs.

Ameren Service Co.[13] involves the proper application of existing Midwest ISO tariff provisions and tariff rules to allocate costs between and among entities that voluntarily elected to participate in the Midwest ISO, and to live by its market and cost allocation rules.[14] The *Northern Indiana Public Service Co.*[15] case concerns a voluntarily negotiated agreement that addressed the cost of the transmission upgrades.[16] The Midwest ISO-PJM Joint Operating Agreement is also an agreement that was negotiated and entered into voluntarily by the two RTOs.[17] The Western System Coordinating Council ("WSCC") decision addressed a dispute regarding how to allocate costs for a regional effort to address loop flows between and among WSCC members.[18] Further, the court decisions cited by Applicants are not applicable, as none involved the issue of inter regional cost allocation to non-customers. Thus, the precedent cited by the Applicants does not support the proposal to reallocate the sunk cost of ITC's Replacement PARs to ratepayers located outside the Midwest ISO that were not participants in the planning of, or the decision to build, the PARs.

- <u>The Proposal to Allocate the Cost of the Replacement PARs to New York and PJM Customers Is Not Consistent With The Method Used To Allocate The Cost Of The Replacement PARs Within the Midwest ISO Region</u>. In the 2006 Midwest ISO Regional Transmission Plan ("MTEP"), which incorporated the Replacement PARs as a project, the Midwest ISO Board of Directors did not identify the "B3N Interconnection" Replacement PAR project as a "Baseline Reliability Project" that was eligible for cost sharing within the Midwest ISO region. Rather, the Midwest ISO Board determined that the cost of the Replacement PARs was not eligible for cost sharing and needed to be recovered from customers located in ITC's traditional service territory.[19] Although the Midwest ISO is proposing to allocate the cost of the Replacement PARs to ratepayers in

[13] *Ameren Service Co.*, 125 FERC ¶ 61,161 (2008).

[14] *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 131 FERC ¶ 61,253 at P 141 ("One example of a voluntary cost recovery arrangement with a public utility is voluntary membership in an RTO or ISO that makes an entity subject to the cost allocation provisions of the RTO's or ISO's tariff." [Citation Omitted]).

[15] 128 FERC ¶ 61,281 (2009).

[16] *See* Application at 12-13.

[17] *See* Application at 14. The NYISO does not attempt to address the application of this complex agreement between Midwest ISO and PJM to the facts presented in this proceeding because it is not a party to the agreement (or to any similar agreement with the Midwest ISO) and because PJM is already participating in this proceeding. For a similar reason, the NYISO does not attempt to address the Midwest ISO's pending Regional Expansion Criteria and Benefits ("RCEB") filing described on pages 14 and 15 of the Application. The NYISO is aware that many PJM, and some Midwest ISO, members have protested the Midwest ISO's proposal in Docket No. ER10-1791, particularly with regard to its attempts to impose involuntary inter-regional cost recovery for "Multi Value Projects."

[18] *See* Application at 13-14.

[19] *See* MTEP06 Appendix A, Project ID Number 1308 (January 30, 2007), available on the Midwest ISO's web site at:

http://www.midwestiso.org/publish/Document/27851_11011a2ccaa_-7d000a48324a/MTEP06_Report_020507.pdf?action=download&_property=Attachment

New York, page 16 of the Application indicates that the Midwest ISO is <u>not</u> proposing to allocate the cost of the Replacement PARs to Midwest ISO customers located outside the "ITC pricing zone." Page 9 of Mr. Grover's Affidavit (Tab G of the Application) states that costs recovered from PJM and NYISO will be "excluded from the ITC *Transmission* Attachment O zonal revenue requirement to prevent double recovery." This statement strongly implies that the costs are not being recovered from any other Midwest ISO zone. In its Application the Midwest ISO seeks permission to recover costs from New York ratepayers that it is not proposing to recover from ratepayers within its own footprint that reside outside ITC's service territory.

B. The Cost Allocation Proposal Is Not Consistent With The Cost Allocation Rules Proposed In The Pending Transmission Planning And Cost Allocation NOPR

- <u>The Commission's Cost Allocation Proposal In *The Transmission Planning And Cost Allocation By Transmission Owning And Operating Public Utilities* Notice Of Proposed Rulemaking ("Transmission Planning NOPR")</u>. In Docket No. RM10-23 the Commission is considering adopting rules addressing cost allocation for transmission facilities. The Application's proposal to allocate costs to New York ratepayers directly contradicts the cost allocation proposal in the Transmission Planning NOPR.

    - For intraregional facilities, the Transmission Planning NOPR proposes:

        > The allocation method for the cost of an intraregional facility must allocate cost solely within that transmission planning region *unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs*. [Emphasis added.][20]

    - For transmission facilities located in two or more regions, the Transmission Planning NOPR proposes:

        > Costs allocated for an interregional facility must be assigned only to transmission planning regions in which the facility is located. *Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located*. [Emphasis added.][21]

    - The Replacement PARs are located in Michigan, which is part of the Midwest ISO's service territory. The Midwest ISO is a member of both Reliability First Corporation and the Midwest Reliability Organization. The New York ISO is responsible for transmission planning in New York State and is a member of the Northeast Power Coordinating Council, Inc. The New York ISO and Midwest

[20] Transmission Planning NOPR at P 164(4).

[21] *Id*. at P 174(4).

ISO do not share a common border, they are separated by the Province of Ontario, Canada and by PJM. The Commission's proposal appropriately rejects efforts to reallocate the cost of transmission facilities to entities outside the transmission planning region(s) in which the facility is located unless a voluntary agreement is reached.

- The Transmission Planning NOPR is also clear that costs associated with a project that is not included in a region's transmission plan "may not be recovered through a transmission planning region's cost allocation process."[22] Applicants should not be allowed to impose the cost of the Replacement PARs on New York customers when a developer that sought to allocate the costs of transmission facilities physically located in New York would not be eligible to do so without first participating in the NYISO's established planning processes.

C. "Benefits" That The Ontario/Michigan PARs Are Expected To Provide

- The Benefit The NYISO Expects Is The Removal Of Unscheduled Ontario And Midwest ISO Power Flows From The New York State Transmission System. The Application cites prior NYISO statements regarding expected benefits to New York at times when the Ontario/Michigan PARs are able to better conform actual power flows to match scheduled power flows at the Ontario/Michigan border. Given the emphasis that the Applicants have placed on the NYISO's statements about benefits, the NYISO considers it necessary to clearly explain its position. The primary benefit that the NYISO anticipated in its earlier pleadings was that, when the Ontario/Michigan PARs are able to better conform actual power flows to scheduled power flows at the Ontario/Michigan border, transmission service that is scheduled into, out-of or through the Midwest ISO would actually flow over the Midwest ISO's transmission facilities, not through New York. When generation in Ontario is dispatched to serve load in PJM, the associated transmission service is ordinarily scheduled through the Midwest ISO and the Midwest ISO is paid to transmit the scheduled energy. However, nearly 40% of the power actually flows over the New York State Transmission System as unscheduled, "clockwise" loop flow, increasing costs to New York customers.[23] The benefit that the NYISO referred to in its prior pleadings is the removal of these unscheduled power flows from the New York State Transmission System. From New York's perspective, the described benefit is actually the remedy of an existing detriment. The NYISO does not agree that New York ratepayers should be required to pay for ITC and Midwest ISO to undertake measures to better conform actual power flows to scheduled power flows at the Ontario/Michigan border.

    - The Broader Regional Markets Buy-Through of Congestion Solution Will Enable New York To Charge Scheduling Entities For Unscheduled Power Flows That Cause Congestion In New York. The proposed Broader Regional Markets Buy-

[22] Transmission Planning NOPR at P 96.

[23] When this occurs, customers in the Midwest ISO benefit from their use of the New York State Transmission System because the Midwest ISO was paid to provide transmission service that was actually provided by New York.

Through of Congestion solution to Lake Erie loop flow will permit the NYISO to charge entities scheduling transmission service into, out-of or through the Midwest ISO for the parallel path impacts of their unscheduled flows on the New York State Transmission System.

- The Replacement PARs Must Be Operated In Conjunction With The IESO/Hydro One's PARs To Better Conform Actual Power Flows To Scheduled Power Flows At The Ontario/Michigan Border. The Application suggests that the Replacement PARs will provide benefits to New York and PJM customers by better conforming actual power flows to scheduled power flows at the Ontario/Michigan border. However, the Replacement PARs, by themselves, are not capable of effectively conforming actual power flows to scheduled power flows at the Ontario/Michigan border. There are four transmission lines interconnecting Michigan and Ontario, three of which have PAR control devices located in Ontario that have been in place since 2003, or earlier. The Replacement PARs only affect power flows on one of the four transmission lines that interconnect Michigan and Ontario. As ITC has previously recognized, the Replacement PARs must be operated in coordination with the existing IESO/Hydro One PARs to conform actual power flows to scheduled power flows at the Ontario/Michigan Border.[24] The Applicants have not explained why it is appropriate to charge ratepayers in New York and PJM for "benefits" that PARs that they do not own or operate, and did not pay for, are needed to provide.

- The Ontario/Michigan PARs Are Only One Component of the Solution To Lake Erie Loop Flow. The Application takes some liberties in interpreting statements from the NYISO's prior pleadings with regard to the benefits that the four ISO/RTO region is expected to receive at times when all four sets of Ontario/Michigan PARs are in place and operating to better conform actual power flows to scheduled power flows.[25] For example, on page 6 of the Application ITC and MISO state that "there is agreement that the New PARs are the optimal solution to the Lake Erie loop flow problem…" The Applicants provide no support for this statement. In fact, the NYISO believes the "optimal solution" is to integrate the operation of the Ontario/Michigan PARs into the suite of market-based solutions to Lake Erie loop flow that the Midwest ISO, Independent Electricity System Operator of Ontario ("IESO"), PJM and the NYISO are working with their stakeholders to develop. The NYISO does not expect the Ontario/Michigan PARs to "solve" the Lake Erie loop flow problem. The Broader Regional Market improvements remain a vital component of the solution to Lake Erie loop flow.

[24] *See* n. 49 and n. 78, *infra*.

[25] On their own, the Replacement PARs would have little impact on Lake Erie loop flow. The Replacement PARs can only be effective in conforming actual power flows to scheduled power flows if they are operated in conjunction with PARs located in Ontario.

II. Documents Submitted

1. This Protest;

2. A copy of the Midwest ISO's *Comments on ITC's Request to Amend Presidential Permit*, submitted to the Department of Energy on March 12, 2009 in Docket No. PP-230-4, including as Attachment A thereto the Midwest ISO's proposed Operating Instructions for the Ontario/Michigan PARs ("Attachment A");

3. A copy of the Midwest ISO's October 5, 2010 presentation the NERC Interchange Distribution Calculator Working Group titled *Modeling MI-ONT PARS in IDC* ("Attachment B")[26]; and

4. A copy of the NYISO's October 5, 2010 presentation to the NERC Interchange Distribution Calculator Working Group titled *Modeling MI-ONT PARS in IDC* and prepared in response to the Midwest ISO's presentation ("Attachment C").

III. Protest

A. Overview

The NYISO's Answer first addresses the application of existing Commission precedent to the cost reallocation proposal in the Application. As the NYISO explains in **Section III.C** of this Protest, the NYISO is not aware of ***any*** Commission precedent that supports allocating the cost of transmission facilities that have already been constructed to non-customers located in a different planning region in the absence of a voluntary cost sharing agreement. Because there is no precedent that is directly on-point, the discussion below considers the Application based on the most closely analogous decisions that the NYISO identified, or that the Applicants identified in the Application.

After addressing existing precedent, the NYISO briefly explains that the Applicants' proposal is contrary to the Commission's interregional transmission cost allocation proposal in its Transmission Planning NOPR. Finally, the NYISO explains why the "benefits" New York

[26] The Midwest ISO's presentation to the IDC Working Group used materials that the Midwest ISO first presented to the NERC Operating Reliability Subcommittee on September 22, 2010.

expects to receive at times when the Ontario/Michigan PARs are operated to better conform actual power flows to scheduled power flows at the Ontario/Michigan border do not justify the Applicants' proposal to allocate millions of dollars in transmission costs to New York ratepayers on an annual basis.

B. There is No Basis in Existing Commission Precedent for Granting the Cost Allocation Remedy Sought by Applicants

1. Even For Cost Allocation Within A Single Region, The Commission Has Placed Strict Limits on Cost Sharing

The Commission's default cost allocation mechanism within a region is the license plate rate, which requires that the costs of a transmission provider's facilities be paid for by that transmission provider's customers, irrespective of the benefits those facilities might provide to customers on other interconnected systems. Although the Commission has expressed a desire to move away from license plate rates, and toward postage stamp rates that might better reflect the regional benefits that certain transmission facilities provide, it has repeatedly endorsed – for reasons of equity and efficiency – the use of license plate rates in its efforts to facilitate the development of ISOs and RTOs.[27] In recent years, the Commission has gradually moved toward the use of postage stamp rates, but only for facilities that are to be constructed in the future and that are developed in accordance with a Commission-accepted regional joint planning process.[28] Most significantly, the Commission's movement toward limited postage stamp rates has been accompanied by an insistence that license plate rates be retained for existing facilities.

[27] *See PJM Interconnection, L.L.C.*, 96 FERC ¶ 61,060 at 61,220 (2001); *Cleco Power LLC*, 103 FERC ¶ 61,272 at P 28 (2003); *Southwest Power Pool, Inc*., 111 FERC ¶ 61,118 at P 35 (2005); *Bonneville Power Administration*, 112 FERC ¶ 61,012 at P 96 (2005).

[28] *See, e.g., PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063 (2007), *order on reh'g*, Opinion No. 494-A, 122 FERC P 61,082 (2008); *Midwest Independent Transmission System Operator, Inc.*, 114 FERC ¶ 61,106, *order on reh'g.*, 117 FERC ¶ 61,241 (2006).

a. The Commission has repeatedly rejected a shift to postage stamp rates for existing facilities, particularly where they have been constructed by individual transmission owners to benefit their own customers

Recent Commission decisions addressing the allocations of transmission costs in PJM and the Midwest ISO are directly applicable to the Applicants' request. These decisions, which have repeatedly rejected efforts to impose postage stamp rates for existing transmission facilities, strongly undercut the proposal to reallocate the cost of the Replacement PARs to New York ratepayers.

i. Opinion No. 494

In Opinion No. 494, the Commission's resolution of rate design issues in PJM, the Commission affirmatively rejected a request to implement postage stamp rates for existing facilities. Instead, the Commission required that license plate rates remain in effect for existing transmission facilities, even though many of those facilities provide benefits to ratepayers outside of their local zones.[29]

The Commission's rationale for mandating the use of license plate rates for existing facilities is premised on four core factors. The first is the fact that "existing facilities represent sunk costs that were built primarily by individual utilities to serve their own internal needs and were financed by those utilities."[30] The Commission explained that because "transmission owners in PJM built their existing infrastructure primarily to accommodate the needs of their own customers,"[31] it is appropriate to require that those customers bear the costs of that infrastructure. The Commission rejected arguments that ancillary beneficiaries should bear a portion of the costs of such facilities, even if those benefits are a result of unanticipated or new

[29] Opinion No. 494, 119 FERC ¶ 61,063 at P 49 (2007).

[30] *Id.* at P 50.

[31] *Id.* at P 51.

uses of the system, because the "fact that the transmission system is used today in ways that differ from when the facilities were first constructed does not, standing alone, provide a basis for finding that a license plate rate design is no longer just and reasonable."[32]

The second, related, factor revolves around the fact that the "sunk transmission costs in question were not planned and constructed to maximize benefits on a region-wide basis"[33] as part of a region-wide planning process. Instead, as noted above, the transmission facilities were constructed by each individual transmission owner for the benefit of their own ratepayers. In the absence of a region-wide planning process intended to maximize benefits on a regional basis, the Commission held that it was just and reasonable for the costs of existing transmission facilities to be recovered through license plate rates.

The third factor involves economic efficiency, and the provision of appropriate incentives for construction of new transmission facilities. The Commission noted that "one of the goals in allocating costs is to promote economic efficiency, [and] reallocation of the sunk costs of already built facilities will not affect future investment decisions."[34] The Commission went on to explain that:

> the allocation of the sunk costs of existing transmission facilities has no significant impact on investment decisions associated with new transmission facilities. A reallocation of costs for existing facilities will not affect a transmission owner's future decision about whether and where to build new transmission facilities. Rather, it is the cost allocation method for new transmission facilities that influences the incentive to invest.[35]

[32] *Id.*

[33] *Id.* at P 54.

[34] *Id.* at P 53.

[35] *Id.*

The fourth factor is the fact that "[a]n abrupt shift away from license plate rates would . . . result in inequities within PJM."[36] Specifically, the Commission was concerned that the use of postage stamp rates for existing facilities would abruptly impose additional costs on third parties that had no notice that such costs would be imposed on them, and that had no input into whether, or how, such facilities should be constructed.[37]

Each of the factors listed above dictate against the Applicants' cost sharing proposal. First, as explained below, the original Bunce Creek PAR and the Replacement PARs were constructed to benefit ITC's customers and to satisfy Michigan regulatory requirements. Second, the Replacement PARs were not planned and constructed to maximize benefits to the combined Midwest ISO, PJM, IESO, NYISO region under a planning process that covered the region. As explained below, the Replacement PARs were included in the 2006 MTEP, but they were not determined to be eligible for broad postage stamp cost allocation within the Midwest ISO region. Third, the cost of the Replacement PARs are sunk costs. Permitting ITC to reallocate the cost of these completed transmission facilities is not necessary to incent ITC to construct them, or to permit ITC to obtain the financing necessary to construct them. Finally, granting the Application would abruptly impose additional costs on New York ratepayers that had no notice that such costs would be imposed on them, and that had no input into whether, or how, such facilities should be constructed.

ii. AEP Complaint

The Commission reiterated these holdings in its rejection of a complaint by American Electric Power ("AEP") seeking the imposition of a postage stamp rate for existing facilities in both PJM and the Midwest ISO. Similar to the arguments made by Applicants in this case, AEP

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[36] *Id.* at P 57.

[37] *Id.*

argued that its existing high voltage transmission facilities in the combined PJM/Midwest ISO region provided substantial benefits to customers outside of AEP's zones, and that those customers therefore should bear a portion of the costs of those existing facilities.[38]

The Commission began its discussion by explaining why postage stamp rates are permissible for future facilities, but not for existing facilities. The Commission first contrasted the planning process that led to the construction of AEP's existing facilities with the process used to construct prospective facilities in PJM and the Midwest ISO. The Commission explained that, unlike the process that led to the construction of AEP's existing facilities, "Midwest ISO and PJM plan the construction of new facilities based on each RTO's independent planning process, which helps to ensure that new projects are necessary to meet the reliability and economic needs of each RTO's system as a whole."[39] Equally important, "[s]takeholders in each RTO can participate in the RTO's regional planning process and, thus, can be part of the discussion that leads to the decision to build new facilities in which they will share the cost."[40] By "contrast, decisions to build existing facilities were not made as part of any regional planning process."[41]

The Commission also explained that "unlike existing facilities, the rate design for new facilities has efficiency implications."[42] Specifically, "rate design for new facilities is important because it provides incentives for construction and provides sufficient certainty, so that

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[38] *See American Electric Power Service Corp. v. Midwest Independent Transmission System Operator, Inc., et al.*, 122 FERC ¶ 61,083 at P 31, *order on rehearing*, 125 FERC ¶ 61,341 (2008).

[39] *Id.* at P 96.

[40] *Id.*

[41] *Id.*

[42] *Id.* at P 97.

developers can obtain financing and the projects can be constructed."[43] By contrast, "reallocating the cost of existing facilities would neither provide economic efficiencies nor promote the goal of increasing necessary transmission investment."[44]

The Commission then went on to address AEP's arguments that its facilities were, in fact, planned on a regional basis that justified a postage stamp rate, again, similar to the argument raised in the Application and accompanying affidavits. In response to AEP's argument that it "in fact did coordinate the development of its [high-voltage] system with other utilities in the region," the Commission stated that "AEP has not shown that the level and type of coordination it says occurred in the development of its existing high-voltage facilities is comparable to the RTO regional planning processes currently in place."[45] The Commission noted that while "AEP's facilities were likely not planned in isolation, there is no evidence in the record to show that they were planned to address regional needs of either the Midwest ISO or PJM wholesale market, and therefore they are not comparable to each RTO's regional planning process."[46]

The Commission also addressed the general argument that customers throughout PJM and the Midwest ISO should pay for AEP's existing high voltage facilities because they all benefit from them. In particular, the Commission stated that "[w]e do not dispute that some of AEP's existing facilities provide benefits outside of their local zone, including for Midwest ISO customers."[47] However, the Commission concluded that, "consistent with the Commission's findings in Opinion No. 494, this fact by itself does not establish that the current license-plate

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[43] *Id.*

[44] *Id.*

[45] *Id.* at P 98.

[46] *Id.*

[47] *Id.* at P 133.

rate design for existing facilities is unjust or unreasonable, nor does it provide justification for reallocating the cost of existing facilities throughout the combined Midwest ISO/PJM region."[48]

These decisions are the most recent Commission pronouncements on the permissibility of reallocating sunk transmission costs outside the Order No. 890/Transmission Planning NOPR context, and establish clearly that such costs, having been incurred pursuant to a license plate rate cost allocation methodology, should not later be reallocated to unsuspecting third parties under a postage stamp rate. Beginning in 2008, ITC identified the replacement of the Original Bunce Creek PAR as a capital project to be included in ITC's Attachment O rate – the license plate rate in the Midwest ISO tariff for recovery of ITC's transmission costs from ITC's own customers.[49] There is no reason for the Commission to reach a different conclusion in this case.

b. The Commission's decisions limit postage stamp rates to prospective transmission facilities constructed pursuant to an organized regional planning process

Just as important as the Commission's repeated rejection of the application of postage stamp rates to existing facilities are the limited circumstances under which the Commission has permitted the use of postage stamp rates. The Commission's decisions establish two fundamental prerequisites for the applicability of postage stamp rates – that they be applied to facilities constructed <u>after</u> the relevant postage stamp methodology has been put into effect, and

[48] *Id.*

[49] ITC has included replacement of the Original B3N in its Attachment O as a capital project. *See* International Transmission Company, *ITC Partners in Business 2009 Attachment O* at 9 (listing Midwest ISO Project ID #1308 – B3N ITC-Hydro One Interconnection (Bunce Creek) as a 2009 Planned Capital Addition) and International Transmission Company, *ITCTransmission 2010 Attachment O* at 10. ITC has also discussed the project in several presentations as a replacement of the Original Bunce Creek PAR. *See, e.g.,* International Transmission Company, *ITC Partners in Business Meeting Presentation* at 21 (dated December 13, 2007 (describing it as a project to "Replace the failed B3N phase shifting transformer at Bunce Creek with two phase shifting transformers to be operated in series. Justification Includes – Replace failed equipment."); Spring 2008 ITC Presentation at 9 (stating that "[w]ith PARs on 3 of 4 interconnections, it will not be possible to achieve the goal of flow equal to schedule, particularly when external transactions cause heavy flow conditions. The interconnection will be operated to control flow to schedule as much as possible. This will be the case for Summer 2008. The B3N transformer will be replaced by two (in series) phase angle regulating transformers which are expected to be delivered in late 2008 and early 2009. Once operational, the interconnection flow can be optimally controlled to flow equals scheduled.").

that they be constructed pursuant to a formal, system-wide planning methodology which takes into consideration the needs of the entire region, and which permits all affected stakeholders to participate meaningfully before they are allocated transmission upgrade costs.

i. Prospective Transmission Facilities

As outlined above, one of the core lessons of Opinion No. 494 is that cost allocation for existing transmission facilities is different from cost allocation for proposed/future transmission facilities. Among the reasons for this is the need to encourage efficient construction and siting of new transmission assets. As the Commission observed, the "reallocation of costs for existing facilities will not affect a transmission owner's future decision about whether and where to build new transmission facilities."[50] Rather, "it is the cost allocation method for new transmission facilities that influences the incentive to invest."[51]

Another significant reason for the distinction between existing and proposed facilities is the desire to avoid the inequitable result of unanticipated cost shifts to unsuspecting third party transmission customers. The Commission has consistently sought to avoid the imposition of additional costs on third parties that had no notice that such costs would be imposed on them, or input into whether, or how, such facilities should be constructed.[52]

Largely for these reasons, the Commission has limited the applicability of postage stamp rates to transmission facilities planned and constructed after the implementation of a postage stamp cost allocation methodology.[53] Postage stamp rates have not been available in circumstances, like the ones present in this proceeding, where transmission facilities are

[50] 119 FERC ¶ 61,063 at P 53.

[51] *Id.*

[52] *Id.*

[53] *See* 119 FERC ¶ 61,063 at PP 61-66 (emphasizing that the methodology requiring transmission costs to be paid by all beneficiaries will apply to all "new" transmission facilities).

constructed before a postage stamp rate method is adopted. Only by ensuring that postage stamp rates apply on a prospective basis can the Commission ensure that it is truly providing the correct incentives for the construction of new transmission facilities, and avoid inequitable cost shifts that inevitably accompany the reallocation of sunk transmission costs.

The Commission's decisions requiring license plate cost allocation for transmission facilities is not limited to transmission facilities that have already been placed in service. In the case of the Midwest ISO's transmission facilities in particular, the Commission approved a cost allocation approach that excluded from the newer, system-wide cost allocation mechanism numerous transmission projects that had reached advanced stages in the planning process, but that had not yet been constructed. The Commission rejected challenges to this determination from developers of these excluded projects, noting that they had "moved forward with those projects without any assurance that such projects would be candidates for regional cost-sharing."[54] This holding underscores that the key issue is not whether the underlying transmission facility has been placed into service, but instead whether the developer of that facility has moved forward in its effort to construct that facility before a postage stamp rate was put into effect. There is no postage stamp rate in place for allocating costs across the combined Midwest ISO-PJM-NYISO region.

ii. System-Wide Planning Process

The Commission's second prerequisite to the adoption of a postage stamp rate is the use of "a formal, Commission-approved, regional planning process where the needs of the region are addressed and where all stakeholders are given an opportunity to participate."[55] In its orders on

[54] 117 FERC ¶ 61,241 at P 96.

[55] 122 FERC ¶ 61,083 at P 99. *See also* Opinion No. 494, 119 FERC ¶ 61,063 at P 84 ("facilities that are eligible for postage-stamp treatment will be planned on a regional basis by a central grid operator, PJM, which considers the reliability and economic interests of PJM as a whole.").

the AEP complaint the Commission found that "an important factor in allowing certain new high-voltage facilities to be eligible for postage-stamp treatment is that those new facilities are planned on a regional basis by a central grid operator, who considers the reliability and economic interests of the RTO as a whole."[56]

This factor directly affected the outcome of AEP's complaint because AEP was unable to prove that its existing facilities were constructed pursuant to such a process. As outlined above, AEP provided documentation of collaborations between it and neighboring utilities, in an attempt to satisfy this criterion. Nonetheless, the type of organized process needed to satisfy this criterion is a highly centralized one that formally accounts for all the needs of the relevant region, and that permits all affected stakeholders to participate on a prospective (pre-construction) basis. AEP's collaborations with its neighboring utilities was insufficient to carry AEP's burden of establishing that its existing facilities had been planned pursuant to the necessary regional planning process. The Commission concluded that "[a]lthough AEP's facilities were likely not planned in isolation, there is no evidence in the record to show that they were planned to address regional needs of either the Midwest ISO or PJM wholesale market, and therefore they are not comparable to each RTO's regional planning process."[57]

2. The Application Does Not Demonstrate That the Prerequisites to the Adoption of Regional Cost Sharing for the Replacement PARs are Satisfied

All of the circumstances that the Commission relied on in rejecting postage stamp rates for existing facilities in Opinion No. 494 and in the AEP case are present in this proceeding, and none of the prerequisites to the application of a postage stamp rate have been satisfied.

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[56] 122 FERC ¶ 61,083 at P 99.

[57] *Id.*

a. The Replacement PARs are existing facilities for which the type of cost allocation sought in the Application is not available

One of criteria for regional cost sharing is that the cost sharing mechanism be in place before the underlying transmission assets are planned and constructed. Indeed, the Commission has looked askance at the use of a postage stamp rate in circumstances where "[p]arties moved forward with [their] projects without any assurance that such projects would be candidates for regional cost sharing."[58] Thus, where there are existing facilities – that is, facilities that have undergone either extensive planning or construction, the costs of which are expected to be recovered under a license plate rate – the Commission prohibits a reallocation of such costs pursuant to a postage stamp rate. The reasons for this, again, are to promote efficient transmission development, and to prevent unfair cost shifts to unsuspecting third party customers.

In this case, ITC moved forward with the planning and construction of the Replacement PARs long before it began participating in the process that is currently in place to develop broader regional market solutions to Lake Erie loop flow. Parties outside of the ITC zone had absolutely no notice of any proposal by ITC or the Midwest ISO to allocate such costs to them until after the underlying PARs were either nearly complete or completed.[59] The Replacement PARs are existing transmission facilities for which the type of broad cost allocation sought by ITC is prohibited. The fact that the Replacement PARs have not yet entered service is

[58] *Midwest Independent Transmission System Operator, Inc.*, 117 FERC ¶ 61,241 at P 96 (2006).

[59] ITC did not propose or request broader allocation of the cost of its PARs until more than eight years after ITC initially proposed to construct the original Bunce Creek PAR. It was not until the NYISO brought the incidental benefits these facilities could provide to other ratepayers to the Commission's attention that ITC began requesting broader allocation of the cost of its facilities. ITC first began making these arguments in pleadings seeking to dissuade the NYISO and the Commission from involving themselves in the Department of Energy permitting process for the Bunce Creek PARs. *See, e.g.*, ITC's *Answer In Opposition to Request for Clarification* at 3 (August 31, 2009).

irrelevant.[60] Granting the Application would unfairly reallocate part of the costs of the Replacement PARs to New York ratepayers, without ever giving them a chance to weigh in on the planning or construction of those facilities, in contravention of established Commission precedent. Furthermore, granting the cost allocation proposed in the Application would constitute the very type of reallocation of sunk costs that the Commission has repeatedly concluded would adversely affect efficient transmission construction decisions. The Application should be rejected.

b. ITC constructed the original Bunce Creek PAR and the Replacement PARs in order to benefit its own ratepayers, and to satisfy the requirements of the Michigan retail access statute, and not to provide interregional benefits

As the Commission established in Opinion No. 494, broad cost allocation is not warranted in circumstances where "existing facilities represent sunk costs that were built primarily by individual utilities to serve their own internal needs and were financed by those utilities."[61] It is for this reason that the Commission, in its rejection of the AEP complaint, held that "[w]ithin the context of RTOs, examining the original basis for making an investment is a reasonable component of a rate design analysis."[62]

A review of the "original basis" for the PARs shows that they were designed and constructed primarily for the benefit of ITC's ratepayers and to achieve compliance with Michigan's electric retail access statute. The original Bunce Creek PAR was not designed pursuant to the type of formalized, (inter)regional planning process necessary to justify an

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[60] As outlined above, the Commission's decisions regarding the Midwest ISO cost allocations excluded from postage stamp rates facilities that had not yet been constructed, but that had advanced substantially through the planning process. *See Midwest Independent Transmission System Operator, Inc.*, 117 FERC ¶ 61,241 at P 96.

[61] Opinion No. 494, 119 FERC ¶ 61,063 at P 50.

[62] 125 FERC ¶ 61,341 at P 41.

allocation of ITC's costs to New York ratepayers. ITC conceded this in a pleading it submitted to the Commission earlier this year.[63]

The construction of a PAR at Bunce Creek Station was originally proposed by Detroit Edison – ITC's predecessor-in-interest – in 2000. In its April 2000 application to amend its Presidential Permit to allow the construction of the original Bunce Creek PAR, Detroit Edison explained that the installation of the original Bunce Creek PAR would "provide enhanced control over the inadvertent power flow between Michigan and Ontario, and by extension, around the Great Lakes."[64]

In December of 2000, the Michigan Public Service Commission ("MPSC") initiated a proceeding, requiring electric utilities serving more than 100,000 retail customers in Michigan, to file a joint plan detailing measures to expand available transmission capability by at least 2000 MW, by June 5, 2002. The MPSC imposed this requirement to comply with Section 10v of Michigan's Customer Choice and Electric Reliability Act, 2000 PA 141 ("Section 10v").[65]

In the resulting MPSC proceeding, Detroit Edison, and its then-subsidiary, ITC, filed a Joint Report "detailing the actions required to achieve the 2000 MW expansion, including identifying the facilities required."[66] The Joint Report identified seven projects that ITC would

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[63] *See Motion for Leave to Answer and Answer of International Transmission Company d/b/a ITC Transmission*, Docket No. ER08-1281-000 (March 1, 2010) at 7 (acknowledging that no formalized planning process existed "when the PARs were planned").

[64] *The Detroit Edison Company*, Presidential Permit Order No. P-221 at 2 (April 27, 2000) ("April 2000 Presidential Permit").

[65] *See In the Matter of the application of Indiana Michigan Power Co., d/b/a American Electric Power, for approvals in connection with 2000 PA 141 Section 10v; In the matter of the application of International Transmission Company and Great Lakes Energy Cooperative for approvals in Connection with 2000 PA 141 Section 10v*, Brief of the Detroit Edison Co. at 1-2, MPSC Docket Nos. U-12780 and U-12781 (filed June 29, 2001) ("Detroit Edison Brief"); *see also*, MPSC Docket Nos. U-12780 and U12781, *ITC Testimony of T.W. Vitez* at 16 (filed March 17, 2001).

[66] *Id.* at 2.

have to build, in order to meet the requirements of Section 10v.[67] One of the projects ITC identified was the addition of "a 675 MVA Phase Angle Regulator in the B3N interconnection with Hydro One [*i.e.*, the original Bunce Creek PAR]."[68]

In the Joint Report, ITC stated that it had installed the original Bunce Creek PAR which was:

> operating in concert with similar phase angle regulators added by Hydro One in the L4D and L51D interconnections, as well as the existing phase angle regulator in the J5D interconnection, [and] enables the control of 600-700 MW of parallel path flow north of Lake Erie (Lake Erie circulation). As this circulating power was using a significant portion of the International Transmission Company-Ontario interface, the control of 600-700 MW of circulating power translates into an increase in the firm commercial capability of that interface. **In total, the Hydro One to MECS path will realize an increase of 820 MW of firm commercial capability from 2000 to 2002**.[69] (Emphasis added.)

The Joint Report indicated that ITC was "committed to constructing all of the identified projects" which were required to comply with Section 10v.[70] In a subsequent pleading with the MPSC, DTE and ITC stated that "adding a 675 MVA phase angle regulator in the B3N interconnection with Hydro One" was part of the projects "required to be completed on ITC's system in order to support the expansion by 2000 MW, of the firm commercial capability into the lower peninsula of Michigan."[71] In July of 2002, the MPSC issued an order finding that the Joint Report complied with state law and stated that the proposal "will achieve the required increase in transmission capacity."[72]

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[67] *See* MPSC Docket Nos. U-12780 and U12781, *ITC Testimony of T.W. Vitez - Exhibit 2 "Joint Report"* at 1 (filed March 17, 2001) (The Joint Report was produced by ITC, along with Consumers Energy Company and Great Lakes Energy Company) ("Joint Report").

[68] Detroit Edison Brief at 5.

[69] Joint Report at 8.

[70] *Id.* at 12.

[71] Detroit Edison Brief at 1-2.

[72] MPSC Docket Nos. U-12780 and U12781, Opinion and Order (issued July 23, 2002).

In April of 2001, the Department of Energy issued a Presidential Permit to ITC,[73] authorizing the construction of the original Bunce Creek PAR.[74] The original Bunce Creek PAR entered service in 2003, but failed in March of that year.[75] Later, in April of 2003, the tower supporting the Canadian side of the underlying transmission line (the Bunce Creek - Scott line) collapsed due to inclement weather, causing the line itself to fail.[76] In November of 2006, Hydro One replaced the tower and restrung the Bunce Creek-Scott transmission line.[77] In 2009 and 2010, ITC identified the replacement of the original Bunce Creek PAR as a capital project to be included in ITC's Attachment O rate – that is, the license plate rate in the Midwest ISO tariff for recovery of ITC's transmission costs from ITC's own customers.[78] Replacement of the original Bunce Creek PAR was also listed in the 2006 Midwest ISO Transmission Expansion Plan as a project recommended by the Midwest ISO to meet system needs, but not eligible for cost

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[73] ITC and Detroit Edison had restructured and applied to the DOE to rescind the Presidential Permit granted to Detroit Edison and concurrently issue a new Presidential Permit to ITC for the same facilities. That request was authorized on September 26, 2000 in Presidential Permit Order No. PP-230. *See* April 2001 Presidential Permit at 3.

[74] *See* April 2001 Presidential Permit at 1.

[75] *International Transmission Company d/b/a ITCTransmission*, Request of International Transmission Company D/B/A ITC*Transmission* to Amend Presidential Permit at 5, DOE Docket No. PP-230-4 (filed January 5, 2009) ("January 2009 Presidential Permit Application"); International Transmission Company, *Partners in Business Presentation* at 8, Spring 2008 ("Spring 2008 ITC Presentation").

[76] *See* January 2009 Presidential Permit Application at 5 and Spring 2008 ITC Presentation at 8.

[77] *See* Spring 2008 ITC Presentation at 8.

[78] ITC has identified replacement of the original Bunce Creek PAR in its Attachment O presentations as a capital project. *See* International Transmission Company, *ITC Partners in Business 2009 Attachment O* at 9 (listing Midwest ISO Project ID #1308 – B3N ITC-Hydro One Interconnection (Bunce Creek) as a 2009 Planned Capital Addition) and International Transmission Company, *ITCTransmission 2010 Attachment O* at 10. ITC has also discussed the project in several presentations as a replacement of the original Bunce Creek PAR. *See, e.g.*, International Transmission Company, *ITC Partners in Business Meeting Presentation* at 21 (dated December 13, 2007 (describing it as a project to "Replace the failed B3N phase shifting transformer at Bunce Creek with two phase shifting transformers to be operated in series. Justification Includes – Replace failed equipment."); Spring 2008 ITC Presentation at 9 (stating that "[w]ith PARs on 3 of 4 interconnections, it will not be possible to achieve the goal of flow equal to schedule, particularly when external transactions cause heavy flow conditions. The interconnection will be operated to control flow to schedule as much as possible. This will be the case for Summer 2008. The B3N transformer will be replaced by two (in series) phase angle regulating transformers which are expected to be delivered in late 2008 and early 2009. Once operational, the interconnection flow can be optimally controlled to flow equals scheduled.").

sharing.[79] As the Midwest ISO has established in its Regional Transmission Plan, projects that are not eligible for cost sharing include those that are "under the threshold for regional cost sharing, are driven by local area planning criteria … and are therefore not eligible for cost sharing but should nevertheless be implemented with the costs recovered by the Transmission Owner within the associated pricing zone."[80]

On January 5, 2009, ITC filed an application to amend its Presidential Permit. Specifically, ITC requested approval to place into service two 700 MVA phase shifting transformers (the Replacement PARs) to replace the "previously authorized 675-MVA transformer" (the original Bunce Creek PAR).[81] ITC asserted that the original Bunce Creek PAR's "purpose was to help provide 'enhanced control over the inadvertent power flow between Michigan and Ontario and, by extension, around Lake Erie', so that 'under normal operating conditions … the electrical flow on the Michigan-Ontario interface will match the Michigan-Ontario scheduled transactions across the interface.'"[82] Further, ITC stated that:

> [i]n recognition of the failure of the original transformer … ITC chose a differently designed unit and decided to replace the single failed unit with two 700-MVA units connected in series…. Since the two new transformers will nominally have 15 degrees more shifting capability than the failed transformer, they should be capable of providing some increased amount of control over unscheduled electrical flows when necessary. **However, the intended function of the new units will be the same as the original unit was authorized to provide in 2001** -- to control unscheduled flows so that actual flow matches scheduled flow, to the maximum extent possible. **In that sense, therefore, the new units should perhaps best be viewed as replacement facilities providing an already authorized service, rather than as new facilities providing a new service.**[83] (Emphasis added.)

[79] *See Midwest ISO Transmission Expansion Plan - MTEP06* at 7 (revised February 2007); *MTEP06 Appendix A*, Project ID Number 1308 (January 30, 2007).

[80] *Midwest ISO Transmission Expansion Plan - MTEP06* at 7.

[81] January 2009 Presidential Permit Application at 5-6.

[82] *Id.* at 5.

[83] *Id.* at 6.

This history demonstrates that the original Bunce Creek PAR was constructed by Detroit Edison with the needs of its own ratepayers in mind, and for the purpose of satisfying Michigan's electric retail access requirements. ITC's presidential permit application emphasizes that the replacement PARs were constructed for the same purposes as the original Bunce Creek PAR. Thus, like the existing facilities in Opinion No. 494 and in the AEP complaint proceeding, the Bunce Creek PARs were built for the benefit of ITC's own ratepayers, and – in spite of any ancillary benefits that those facilities might have for other areas around Lake Erie – not for the benefit of the broader region.

c. The Replacement PARs were not planned and constructed pursuant to the type of formalized planning process that is a prerequisite to the type of cost allocation proposed in the Application

The history of the Replacement PARs outlined above belies the arguments throughout Mr. Webb's affidavit that they were somehow constructed pursuant to the type of regional planning process required to justify the cost allocation that the Applicants now seek. The specific requirement is that there be a "formal, Commission-approved, regional planning process where the needs of the region are addressed and where all stakeholders are given an opportunity to participate."[84] As outlined above, informal discussions or collaborations are not sufficient to satisfy this criterion. Rather, a proponent of a broad cost allocation must demonstrate that a formalized, regional planning process was in place at the time that the underlying facilities were planned, that it considered the needs of the entire region, and that it permitted all affected stakeholders to have a say over whether and, if so, how the relevant facilities will be constructed.

ITC did not propose to allocate costs associated with the original Bunce Creek PAR to New York ratepayers. To the extent that the NYISO and New York ratepayers have had any

[84] 122 FERC ¶ 61,083 at P 99.

discussions with ITC, the Midwest ISO, or any other entity regarding the Replacement PARs, those discussions have been informal and operational in nature, and have not been part of the type of formalized, regional planning process that is a prerequisite to the cost allocation sought by ITC. Neither the NYISO nor New York ratepayers have been brought into, or been permitted to participate in, the design, planning, or installation process for the Bunce Creek PARs, and have had no say regarding the nature or amount of the PARs expenditures incurred by ITC. Furthermore, there has been no formalized process in place to encourage such participation, and any discussions that the NYISO or New York ratepayers have had with other entities regarding the original Bunce Creek PAR and the Replacement PARs have been only informal communications, largely at the operational (as opposed to the planning) level.

This is borne out by the limited documentation that the Applicants cite in support of their "regional planning" claims – a 1999 MAAC-ECAR-NPCC (MEN) study titled *Michigan-Ontario Phase Angle Regulator Study An Interregional Perspective* (the "MEN study") a joint PJM-Midwest ISO report, and documentation of the Midwest ISO Board's approval of the 2006 Midwest ISO Regional Transmission Plan ("MTEP"), which incorporated the Replacement PARs as an MTEP project. The PJM-Midwest ISO report is not a formalized planning document. Rather, as its terms make clear, it is a report on the existing status of loop flow issues, and a description of operational measures being taken by PJM and the Midwest ISO to address loop flows.[85] In any case, the NYISO was not a sponsor of that study. The NYISO did not participate in the MISO's MTEP process, and notes that in the MTEP process the Replacement PARs were not eligible for cost sharing within the Midwest ISO region. The 1999

[85] *See* Investigation of Loop Flows Across Combined Midwest ISO and PJM Footprint, May 25, 2007 at 3-4 (stating that the purpose of the initiative is "to provide details on plans and actions taken to address the problems of external loop flows") (available at http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20070525-loop-flow-investigation-report.pdf).

MEN study focused on the expected impact of the Ontario/Michigan PARs including the original Bunce Creek PAR. The MEN study estimated the impact that the operation of the Ontario/Michigan PARs would have on interregional transfer capabilities and interregional power flows under a series of operating scenarios. The study did not identify a significant risks to the reliability of the interconnected system, so long as appropriate emergency procedures for the Ontario/Michigan PARs operation were in place. The MEN study's scope did not include determining or assessing whether the original Bunce Creek PAR was appropriately designed, or whether it was the best, most cost effective, or the most appropriate facility to construct.

The Application does not identify any formal multi-regional planning process that resulted in the construction of the Replacement PARs, to which the NYISO was a party. The Applicants cannot demonstrate that the Replacement PARs were the subject of a regional planning process that included New York ratepayers. ITC and its predecessors planned and constructed both the original Bunce Creek PAR and the Replacement PARs *before* it commenced its opportunistic pursuit of cost contributions from New York and PJM.

The NYISO's position that the PARs were not developed pursuant to a regional planning process is bolstered by the terms and conditions that the Midwest ISO included in a draft set of Ontario/Michigan PAR Operating Instructions that it submitted to the Department of Energy in March of 2009. The draft Operating Instructions are included as an attachment to Attachment A to this Protest. Proposed Sections 5.1(c) and (d) of the attached draft Operating Instructions assigns a higher priority to relieving local congestion in Michigan and Ontario than to conforming actual power flows to scheduled power flows at the Ontario/Michigan border. Proposed Section 7.0 provides that the PAR settings will be determined once each hour "based on a best estimate of the next hour target flow to meet the agreed upon schedule" and ramped at the top of the hour. Section 7.0 also provides that the Midwest ISO and IESO will not move the Ontario/Michigan PARs to correct actual power flows to match scheduled power flows in-hour (without regard to the extent of the mismatch), unless the fact that the PARs are off schedule creates a reliability concern, or causes local congestion in Michigan or Ontario.

Proposed Attachment SS that is included in Tab C to the Application is described on pages 5-6 of Mr. Zwergel's testimony. Mr. Zwergel explains:

> The Midwest ISO has proposed additional Tariff language which states that **if the Midwest ISO determines** that the normal operation of the Michigan-Ontario PARs results in **anomalous Midwest ISO market results**, the Midwest ISO will consult with the Midwest ISO's Independent Market Monitor ("IMM"), the Independent Electricity System Operator ("IESO") and other relevant Reliability Coordinators (such as P JM Interconnection, LLC ("PJM") and the New York Independent System Operator ("NYISO")) as appropriate to determine whether the Midwest ISO should temporarily suspend normal operation of the Michigan-Ontario PARs. ITC will not be consulted and will not play a role in the Midwest ISO's determination of whether to suspend normal operation of the Michigan-Ontario PARs pursuant to Schedule SS-1.
>
> **If the Midwest ISO determines** that normal operation of the Michigan-Ontario PARs needs to be suspended, the Midwest ISO will coordinate the change in Interface control status with the IESO. [Emphasis added.]

Proposed Schedule SS-1 provides that when the Midwest ISO determines that the Midwest ISO's market is being adversely impacted by the operation of the PARs, the Midwest ISO will decide if the operation of the PARs should be suspended, after consulting with the Midwest ISO IMM, IESO, the NYISO and PJM. Proposed Schedule SS-1 only addresses Midwest ISO market impact, and leaves ultimate decision-making authority entirely in the hands of the Midwest ISO. The NYISO was not asked to opine on the one-sided provisions of this proposed rate schedule (or on the Application, for that matter) before it was submitted to the Commission.

Attachment B to this Protest is the Midwest ISO's presentation to the NERC IDC Working Group. It proposes a change to the IDC's PAR modeling method for the modeling of the Ontario/Michigan PARs. Under the Midwest ISO's proposal, the PARs would be treated as "regulating" without regard to how closely actual power flows conform to scheduled power flows at the Ontario/Michigan border, so long as all of the four PARs still have additional taps available (see Slide #6). When the PARs are "regulating" the Midwest ISO proposed that the Michigan/Ontario interface be modeled as an "open circuit." In other words, as if the breakers connecting Michigan and Ontario had been thrown open and the two control areas were no longer directly interconnected. If this proposal is implemented, it would practically exempt all transactions scheduled into, out-of or through the Midwest ISO from requests for reliability curtailments using the NERC Transmission Line Loading Relief ("TLR") process. The NYISO would not be able to use the TLR process to remove transactions scheduled through the Midwest ISO's Control Area that are creating reliability concerns in New York, not even when actual power flows at the Ontario/Michigan border diverge significantly from scheduled power flows. Even when the PARs are not regulating, the Midwest ISO proposed to protect all transactions scheduled across the Ontario/Michigan interface from possible TLR curtailment without regard to the transactions' transmission priority.

Attachment C to this Protest is the NYISO's presentation to the NERC IDC Working Group responding to the Midwest ISO presentation included as Attachment B. The NYISO's presentation explains a number of significant problems created by the Midwest ISO's PAR modeling proposal. The NERC IDC Working Group did not approve the Midwest ISO's proposal.

The Applicants have not involved the New York ISO in their efforts to plan and implement the Ontario/Michigan PARs. Moreover, the documents that the NYISO has attached to this Protest suggest that the Midwest ISO intends to use its authority to operate the

Ontario/Michigan PARs to benefit customers located within its footprint, not to provide broad regional benefits.

Just as AEP was unable to satisfy its burden of demonstrating that its existing facilities were planned and constructed pursuant to a formalized, region-wide planning process, the Applicants have also failed to demonstrate that the Bunce Creek PARs were planned and constructed pursuant to a formalized, region-wide planning process. The NYISO submits that the Applicants have not and cannot identify a multi-region planning process that satisfies the Commission's joint planning prerequisite, because no such joint planning process occurred. There was no process in place for the NYISO or New York ratepayers that are not also, coincidentally, participants in the Midwest ISO's markets, to have any say regarding the design, planning, or construction of the Replacement PARs. In light of these circumstances, there is no basis under applicable Commission orders for granting the cost allocation proposed in the Application.

d. The proposal to allocate the cost of the Replacement PARs to New York and PJM ratepayers is not consistent with the method used to allocate the cost of the replacement PARs within the Midwest ISO region

In the 2006 MTEP, which incorporated the Replacement PARs as a project, the Midwest ISO Board of Directors did not identify the "B3N Interconnection" Replacement PAR project as a "Baseline Reliability Project" that was eligible for cost sharing within the Midwest ISO region. Rather, the Midwest ISO Board determined that the cost of the Replacement PARs was not eligible for cost sharing and needed to be recovered from customers located in ITC's traditional service territory.[86] Although the Midwest ISO is proposing to allocate the cost of the

[86] *See* MTEP06 Appendix A, Project ID Number 1308 (January 30, 2007), available on the Midwest ISO's web site at:

Replacement PARs to ratepayers in New York, page 16 of the Application indicates that the Midwest ISO is not proposing to allocate the cost of the Replacement PARs to Midwest ISO customers located outside the "ITC pricing zone." Page 9 of Mr. Grover's Affidavit (Tab G of the Application) states that costs recovered from PJM and NYISO will be "excluded from the ITC *Transmission* Attachment O zonal revenue requirement to prevent double recovery." This statement strongly implies that the costs are not being recovered from any other Midwest ISO zone. In its Application the Midwest ISO seeks permission to recover costs from New York ratepayers that it is not proposing to recover from ratepayers within its own footprint that reside outside ITC's service territory. The Application does not explain why it is appropriate to narrowly target recovery of the proposed Midwest ISO share of the cost of the Replacement PARs from only ITC's customers, but it is appropriate to broadly allocate the cost of the Replacement PARs to regions outside the Midwest ISO footprint.

e. The Application does not distinguish its Replacement PARs from other transmission facilities that provide extra-regional benefits, the costs of which are recovered through license plate rates

The Replacement PARs are similar to other existing transmission facilities that provide benefits across a relatively broad geographic area. As the Commission stated with respect to AEP's existing facilities "[w]e do not dispute that some of AEP's existing facilities provide benefits outside of their local zone, including for Midwest ISO customers…. this fact by itself does not establish that the current license-plate rate design for existing facilities is unjust or unreasonable, nor does it provide justification for reallocating the cost of existing facilities throughout the combined Midwest ISO/PJM region."[87] Unless the Applicants are able to show

http://www.midwestiso.org/publish/Document/27851_11011a2ccaa_-7d000a48324a/MTEP06_Report_020507.pdf?action=download&_property=Attachment

[87] 122 FERC ¶ 61,083 at P 133.

that the Replacement PARs satisfy the criteria set forth in the Commission decisions outlined above, the Application does not present a basis for a departure from the license plate rates that currently apply to the Replacement PARs.

The Application does not distinguish the Replacement PARs from other existing transmission facilities that provide benefits outside the region in which they are located, but whose costs are recovered through license plate rates. It is not difficult to identify existing transmission facilities that provide benefits to neighboring regions. For example, when generation in Ontario is dispatched to serve load in PJM, the associated transmission service is ordinarily scheduled through the Midwest ISO and the Midwest ISO is paid to deliver the scheduled energy to PJM. However, over the past seven years nearly 40% of the power that suppliers in Ontario have scheduled to flow through the Midwest ISO to sell to PJM, has actually flowed through New York as unscheduled, "clockwise" loop flow. When this occurs, customers in the Midwest ISO benefit from their unintended, but uncompensated use of the New York State Transmission System because the Midwest ISO is paid to provide transmission service that is actually provided by New York State transmission facilities.

The scenario described above (Ontario generation serving PJM and Midwest ISO loads) occurred regularly in January of 2010. For the weeks of January 6, 2010 and January 13, 2010 the NYISO's Day-Ahead modeling assumptions reflected an expectation that average hourly loop flows would be 600 MW throughout the day. The Day-Ahead loop flow modeling assumption the NYISO used for the month was never less than 500MW of clockwise loop flow.[88] A driver of this January 2010 clockwise Lake Erie loop flow was the sale of Ontario generation to PJM and to the Midwest ISO.

The NYISO submits that there is no basis for distinguishing the Replacement PARs from other existing transmission facilities that are capable of providing benefits outside the region in which the facilities are located. To avoid the endless litigation that permitting *ex post* cost allocation would create, Commission precedent only permits the cost of transmission facilities to be allocated regionally on a prospective basis, and only when transmission facilities are planned and developed pursuant to a process that provides *all* of the entities to which costs will be allocated an opportunity to participate. The NYISO believes this approach is the correct approach.

C. None of the Decisions Cited in the Application Authorize *Ex Post* Cost Allocation to Non-Customers

None of the cases cited by the Applicants' support their proposal to reallocate the sunk costs of ITC's Replacement PARs to non-customers that are not located within (or even adjacent to) the Midwest ISO's footprint and that were not involved in the planning process that resulted in the Replacement PARs' construction. The cases all concern cost sharing under voluntary agreements, or cost sharing among entities that are voluntarily members of a common Regional Transmission Operator ("RTO"), Independent System Operator ("ISO") or other regional organization.

Ameren Service Co.,[89] involved the allocation of certain costs among classes of Midwest ISO market participants and does not address allocations to non-customers in another region. That decision found that the Midwest ISO's currently-effective Revenue Sufficiency Guarantee

[88] Lake Erie loop flow information is available on the NYISO's web site at:

http://www.nyiso.com/public/markets_operations/market_data/power_grid_data/index.jsp

[89] 125 FERC ¶ 61,161 (2008).

("RSG") cost allocation methodology, did not reflect the principles of cost causation because it did not allocate costs to certain Midwest ISO market participants that were causing the costs.[90] *Northern Indiana Public Service Co.*,[91] concerned a voluntarily negotiated agreement for the allocation of transmission upgrade costs among PJM, the Midwest ISO and certain other market participants. Also, the Midwest ISO-PJM Joint Operating Agreement is negotiated agreement entered into voluntarily by the two RTOs.[92]

The Commission decisions accepting a cost allocation proposal among the members of the Western System Coordinating Council ("WSCC")[93] are also inapplicable. Those decisions, which were issued in 1995 before ISOs and RTOs assumed responsibility for regional planning,[94] accepted a cost allocation proposal developed as part of a formalized, organized plan to address parallel path flow issues. The process resulting in the cost allocation methodology was one through which all WSCC members had input and through which those members had attempted to come to a negotiated agreement regarding the cost allocation methodology, but for which certain outstanding issues had to be resolved by the Commission. The Commission acknowledged the voluntary nature of the proposal and noted that it "has consistently rejected unilateral filings by single utilities proposing to impose charges, terms and conditions on a neighboring utility that, according to the filing utility, is responsible for loop flows" and instead

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[90] *Id.* at PP 44, 105 (2008) (stating that "[t]he result of such a cost allocation is that certain *market participants* are paying for [RSG] costs caused by other *market participants*....") (emphasis added).

[91] 128 FERC ¶ 61,281 (2009).

[92] *Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.* (Midwest Independent Transmission System Operator, Inc., Second Revised Rate Schedule FERC No.5 at Section 9.4.3 (Sheet No. 58); PJM Interconnection, L.L.C. Second Revised Rate Schedule FERC No. 38).

[93] The Western Electricity Coordinating Council is the successor to the WSCC "which was formed in 1967 by 40 electric power systems serving all or part of the 14 Western States and British Columbia, Canada"), *see* <http://www.wecc.biz/About/Pages/default.aspx>.

[94] *Southern California Edison Co., et al.*, 70 FERC ¶ 61,087 (1995); 73 FERC ¶ 61,219 (1995).

"has required utilities, in the first instance, to work to resolve these highly complex issues among themselves."[95]

Further, the judicial precedent cited by Applicants does not provide a basis on which to allocate costs to non-customers inter-regionally. The cases cited by the Applicants simply stand for the well-established proposition that costs should be paid by customers who cause them and that, in certain circumstances, costs may be allocated to customers who benefit from the incurrence of costs that they did not cause. In *KN Energy v FERC*,[96] the court found that the Commission could order cost sharing among a natural gas pipeline's sales and transportation customers, even where only the sales customers caused the costs. The decision did not involve entities that were not customers of the pipeline. Moreover, the court's approval of cost allocations to beneficiaries that did not cause them was rooted in the "extraordinary circumstances" associated with the "take or pay crisis" of the time.[97]

Applicants' reliance on *Illinois Commerce Commission v. FERC*,[98] is similarly misplaced. In that decision, the court denied the Commission's proposal to allocate costs of transmission facilities within PJM to certain PJM member entities, on the ground that the Commission had not made an adequate showing of the benefits that those entities received. The other decisions cited by Applicants do not support their contentions as they involve costs allocations among members of an RTO or disputes regarding cost allocation proposals among a

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[95] *Southern California Edison Co., et al.*, 70 FERC ¶ 61,087 at 61,250.

[96] 968 F.2d 1295 (D.C. Cir. 1992).

[97] *See also, American Electric Power Service Corp. v. Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, LLC*, 125 FERC ¶ 61,341 at PP 66-67 (2008) (holding that *KN Energy* did not support the reallocation of sunk costs of existing facilities because *KN Energy* involved "take or pay costs arising from clauses in gas purchase contracts" that were "distinct" from the sunk costs of existing transmission facilities for which AEP sought reallocation).

[98] 576 F.3d 470 (7th Cir. 2009).

transmission provider's customers.[99] There is thus no basis in Commission or judicial precedent for Applicant's proposal.

D. The Cost Allocation Proposed in the Application Is Not Consistent With the Interregional Cost Allocation Proposal Included In The Transmission Planning NOPR

In Docket No. RM10-23 the Commission is considering adopting rules addressing cost allocation for transmission facilities. The Application's proposal to allocate costs to New York ratepayers directly contradicts the Commission's Transmission Planning NOPR. The NOPR proposes the following rules for allocating the cost of transmission facilities located within a single transmission planning region:

> The allocation method for the cost of an intraregional facility must allocate cost solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs.[100]

The Transmission Planning NOPR proposes the following rules for allocating the cost of transmission facilities that are located in two or more transmission planning regions:

> Costs allocated for an interregional facility must be assigned only to transmission planning regions in which the facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located.[101]

Regardless of whether the Replacement PARs are considered an intraregional facility or (for sake of argument) a component of a multi-regional facility, the cost allocation proposal

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[99] *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000) (finding that a broader cost sharing was not necessary as departing customers caused stranded costs); *Pacific Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004) (finding that the Commission had not justified the allocation of CalPX wind-up activities costs based on the size of an entity's CalPX account balance at a certain date); *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (finding that certain Midwest ISO Transmission Owners were properly allocated Midwest ISO administrative costs); *Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009) (upholding the net energy for load cost methodology for NERC costs); *Sithe Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 4-5 (D.C. Cir. 2002) (finding that rates must be based on a cost-causation principle and the Commission failed to justify a cost allocation mechanism's deviation from such principles).

[100] Transmission Planning NOPR at P 164(4).

[101] *Id*. at P 174(4).

included in the Commission's Transmission Planning NOPR would not permit the Applicants to allocate the cost of the Replacement PARs to New York, absent a voluntary cost sharing agreement between the two regions. The Replacement PARs are located in Michigan, which is part of the Midwest ISO's service territory. The Midwest ISO is a member of both Reliability First Corporation and the Midwest Reliability Organization. The New York ISO is responsible for transmission planning in New York State and is a member of the Northeast Power Coordinating Council, Inc. The New York ISO and Midwest ISO do not share a common border, they are separated by the Province of Ontario, Canada and PJM. The Commission's proposal appropriately rejects efforts to reallocate the cost of transmission facilities to entities outside the transmission planning region(s) in which the facility is located unless a voluntary agreement is reached.

The Transmission Planning NOPR is also clear that costs associated with a project that is not included in a region's transmission plan "may not be recovered through a transmission planning region's cost allocation process."[102] The NYISO was never asked to include the Replacement PARs in its Comprehensive System Planning Process documents, and the Replacement PARs are, as would reasonably be expected, not included in any reliability or economic plans in New York. Applicants should not be allowed to impose the cost of the Replacement PARs on New York customers when a developer that sought to allocate the costs of transmission facilities physically located in New York would not be eligible to do so without first participating in the NYISO's established planning processes.

[102] Transmission Planning NOPR at P 96.

For the reasons explained in this Protest, the NYISO does not believe that it is appropriate to allocate a portion of the cost of the Replacement PARs, on an *ex post* basis, to consumers in New York.

E. "Benefits" That The Ontario/Michigan PARs Are Expected To Provide to New York

1. The Benefit The NYISO Expects Is The Removal Of Unscheduled Ontario And Midwest ISO Power Flows From The New York State Transmission System

The Application cites prior NYISO statements regarding expected benefits to New York at times when the Ontario/Michigan PARs are able to better conform actual power flows to match scheduled power flows at the Ontario/Michigan border. Given the emphasis that the Applicants have placed on the NYISO's statements about benefits, the NYISO considers it necessary to clearly explain its position. The primary benefit that the NYISO anticipated in its earlier pleadings was that, when the Ontario/Michigan PARs are able to better conform actual power flows to scheduled power flows at the Ontario/Michigan border, transmission service that is scheduled into, out-of or through the Midwest ISO would actually flow over the Midwest ISO's transmission facilities, not through New York.

When generation in Ontario is dispatched to serve load in PJM, transmission service is ordinarily scheduled through the Midwest ISO and the Midwest ISO is paid to transmit the scheduled energy. However, nearly 40% of the power actually flows through New York as unscheduled, "clockwise" loop flow, increasing costs to New York customers.[103] The benefit that the NYISO raised in its prior pleadings is the removal of these unscheduled power flows from the New York State Transmission System. From New York's perspective, the described

[103] When this occurs, customers in the Midwest ISO benefit from their use of the New York State Transmission System because the Midwest ISO was paid to provide transmission service that was actually provided by New York, and because the Midwest ISO transmission system is less congested than it should be.

"benefit" is actually the remedy of an existing detriment. The NYISO does not agree that this type of benefit justifies the Applicants' proposed allocation of Replacement PAR costs to New York. New York ratepayers should not be required to pay for ITC and Midwest ISO to undertake measures to better conform actual power flows to scheduled power flows at the Ontario/Michigan border.

As discussed in Section III.B.2.e of this Protest, above, the Midwest ISO benefits from its unscheduled use of elements of the New York State Transmission System. Neither the NYISO nor New York Transmission Owners have asked the Midwest ISO or its customers to pay for a portion of the cost of constructing, operating or maintaining elements of the New York State Transmission System that provide benefits to the Midwest ISO. However, it would be possible for the NYISO and its Transmission Owners to "cherry pick" elements of the New York State transmission system that provide benefits to the Midwest ISO and to submit a filing proposing to allocate a portion of the cost of those facilities to ratepayers in Michigan and other Midwest ISO states based on the "benefits" that elements of the New York State Transmission System provide. The NYISO believes that the better option is to follow the Commission's lead in the Transmission Planning NOPR and limit cost allocation for extra-regional benefits to new transmission facilities that are jointly planned to benefit both regions, and that are subject to voluntary cost allocation agreements.

2. The Broader Regional Markets Buy-Through of Congestion Solution Will Enable New York To Charge Scheduling Entities For Unscheduled Power Flows That Cause Congestion In New York

The proposed Broader Regional Markets Buy-Through of Congestion solution to Lake Erie loop flow will permit the NYISO to charge entities scheduling transmission service through the Midwest ISO for the parallel path impacts of their unscheduled flows on the New York State

Transmission System. This Broader Regional Markets solution will help protect New York loads from congestion costs caused by unscheduled power flows and will provide "insurance" against TLR-based transaction removal or curtailment to transactions that elect to pay for their congestion impact on the New York State Transmission System. This proposed market solution is capable of supplementing, or providing an alternative to the operation of the Ontario/Michigan PARs.

3. The Replacement PARs Must Be Operated In Conjunction With The IESO/Hydro One's PARs To Better Conform Actual Power Flows To Scheduled Power Flows At The Ontario/Michigan Border

The Application suggests that the Replacement PARs will provide benefits to New York and PJM by better conforming actual power flows to scheduled power flows at the Ontario/Michigan border. However, the Replacement PARs, by themselves, are not capable of conforming actual power flows to scheduled power flows at the Ontario/Michigan border. There are four transmission lines interconnecting Michigan and Ontario, three of which have PAR control devices located in Ontario that have been in place since 2003, or earlier. The Replacement PARs only affect power flows on one of the four transmission lines that interconnect Michigan and Ontario. The Replacement PARs must be operated in coordination with the existing IESO/Hydro One PARs to better conform actual power flows to scheduled power flows at the Ontario/Michigan Border. The Applicants have not explained why it is appropriate to charge ratepayers in New York and PJM for "benefits" that PARs that they do not own or operate, and did not pay for, provide.

4. The Ontario/Michigan PARs Are Only One Component of the Solution To Lake Erie Loop Flow

The Application takes liberties in interpreting statements from the NYISO's prior pleadings with regard to the benefits that the four ISO/RTO region is expected to receive at times when all four sets of Ontario/Michigan PARs are in place and operating to better conform actual power flows to scheduled power flows at the Ontario/Michigan border.[104] For example, on page 6 of the Application ITC and MISO state that "there is agreement that the New PARs are the optimal solution to the Lake Erie loop flow problem…" The Applicants provide no support for this statement. In fact, the NYISO believes the "optimal solution" is to integrate the operation of the Ontario/Michigan PARs into the suite of market-based solutions to Lake Erie loop flow that the Midwest ISO, Independent Electricity System Operator of Ontario ("IESO"), PJM and the NYISO are working with their stakeholders to develop. The NYISO does not expect the Ontario/Michigan PARs to "solve" the Lake Erie loop flow problem. The Broader Regional Market improvements remain a vital component of the solution to Lake Erie loop flow.

IV. Communications

Communications and correspondence regarding this Protest should be directed to:

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[104] On their own, the Replacement PARs have little impact on Lake Erie loop flow. The Replacement PARs can only be effective in reducing loop flow if they are operated in conjunction with PARs located in Ontario.

V. Conclusion

WHEREFORE, for the foregoing reasons, the Commission should reject the Application.

Respectfully submitted,

/s/ Alex M. Schnell

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November 17, 2010

Attachment A

Copy of the Midwest ISO's *Comments on ITC's Request to Amend Presidential Permit*, submitted to the Department of Energy on March 12, 2009 in Docket No. PP-230-4, including as Attachment A thereto the Midwest ISO's proposed Operating Instructions for the Ontario/Michigan PARs

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

International Transmission Company d/b/a ITC*Transmission*	))))	**Docket No. PP-230-4**

COMMENTS OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. ON INTERNATIONAL TRANSMISSION COMPANY, D/B/A ITC*TRANSMISSION*'S REQUEST TO AMEND PRESIDENTIAL PERMIT

The Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") submits these comments in response to International Transmission Company d/b/a ITC*Transmission*'s request to amend Presidential Permit PP-230-3.

A. Background

On January 5, 2009, International Transmission Company, d/b/a ITC*Transmission* ("ITC") filed its request to amend Presidential Permit PP-230-3. As explained in the request, ITC wishes to replace the damaged 675 MVA Bunce Creek Phase Angle Regulator ("PAR") with two 700 MVA PARs in series. *See*, Request of ITC to Amend Presidential Permit ("ITC Request"), p. 1.

The Midwest ISO files these comments in support of the ITC petition. The return to service of the B3N line and the Bunce Creek PAR will provide significant operational and reliability benefits affecting the flow of energy across the interface between the United States and Canada. As noted by ITC, the operation of the PARs have been documented as one important measure that can be used to address the effects of loop flows around Lake Erie. *See*, ITC Request, p. 7, citing the Midwest ISO and PJM study "Investigation of Loop Flows Across Combined Midwest ISO and PJM Footprints."

The Midwest ISO does, however, seek clarification of certain language used to describe the appropriate operation of the PARs, and clarification of the appropriate authority of the Midwest ISO with regard to its role as Reliability Coordinator.

B. Appropriate Operation of the PARs

ITC proposes to operate the PARs "to control unscheduled flows so that actual flow matches scheduled flow, to the maximum extent *possible*." *See*, ITC Request, p. 6. Later, ITC refers to "matching actual power flows to scheduled flows to the maximum *practical* extent." *See*, ITC Request, p. 7.

The 2003 DOE order amending PP-230-3 provides, in Article 3, at page 4, that ITC shall operate the PARs under normal conditions "such that the electrical flow on the Michigan-Ontario interface will match Michigan-Ontario scheduled transactions across the interface." At various time since the issuance of that order, ITC has informed the Midwest ISO that ITC reads the 2003 presidential permit as imposing an absolute limit on the operation of the PARs to "match" actual to scheduled flows.

This position has frustrated the implementation by Midwest ISO of an operating instruction with IESO, the Canadian independent system operator, regarding the operation of the PARs.[1] Good utility practice recognizes that PARs cannot be safely operated to continuously and perfectly match actual to scheduled flows. To attempt to do so would damage the PARs. The Midwest ISO cannot unilaterally direct the operation of the PARs under the operating instruction with IESO because the ITC facilities subject to

[1] See Operating Instruction MISO-IESO-CO2-R0, attached hereto as Exhibit A. Pursuant to a Coordination Agreement between Midwest ISO and IESO, the parties implement certain reliability related activities such as outage coordination and voltage control through detailed Operating Instructions.

the DOE permit have not been transferred to the functional control of the Midwest ISO, as explained in the following section of these comments.[2]

The Midwest ISO respectfully requests that any final order amending permit PP-230-3 clarify that the PARs be operated to match actual power flows to scheduled flows "within practical considerations." This is consistent with the language found in Exhibit A[3].

C. Functional Control of the Interface Facilities

1. <u>Legal Status of Facilities Subject to permit PP-230-3</u>

In reviewing the previous filings in this docket, it appears that ITC made commitments at both FERC and the DOE regarding its intent to transfer functional control of the PARs to the Midwest ISO:

> The Purchase Agreement provides that Applicants will use their best efforts to effect the subsequent transfer to the Midwest Independent Transmission Operator, Inc. ("MISO") of the International Transmission's operational responsibility and control of the phase angle regulators that comprise part of the facilities owned by International Transmission at the Michigan-Ontario, Canada international border.

Joint Application, DOE Docket No. PP-230-3, p. 4.

At the same time, similar representations were made to the FERC regarding functional control of the PARs, as indicated by the final order of the Commission:

> Applicants also emphasize that International Transmission would continue as a member of the Midwest ISO, in accordance with ITC-MISO Agreement approved by the Commission. Applicants state that there will be no effect on the terms or conditions of transmission services that are currently provided to customers over the International Transmission system under the Midwest ISO OATT and Midwest ISO JOATT. *In addition, Applicants assert that*

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[2] *See also*, Application of the Midwest ISO to Export Electric Energy to Canada, Docket No. EA-343, July 10, 2008. As noted in Exhibit C to the July 10 Application, Midwest ISO members Northern States Power and Minnesota Power have transferred functional control of their border facilities to the RTO. Minnkota Power Cooperative is not a Midwest ISO member.

[3] *See* Exhibit A, Section 5.1 (d).

> *they will use their best efforts to facilitate the transfer to the Midwest ISO of International Transmission's operational responsibility and control of the phase angle regulators (PARs) that comprise part of the facilities owned by International Transmission at the Michigan-Ontario, Canada international border.*

ITC Holdings Corp., et al, 102 FERC ¶ 61, 182, at P. 12 (emphasis added).

Finally, the Presidential Permits issued by DOE in both 2001 and 2003 appear to contemplate a transfer of functional control, presumably on the basis of these representations, when the DOE conditioned the orders on operation of the PARS in compliance with policies and standards of Midwest ISO, among others:

> The facilities described in Article 2 above, including the phase-shifting transformer in the B3N circuit, shall be designed and operated in compliance with all policies and standards of NERC or its successor, Regional Councils, *or independent system operators, as appropriate,* on such terms as expressed therein, and as such criteria, standards, and guides may be amended from time to time.

DOE Order, Docket No. PP-230-3, Article 3, at p. 4 (2003) and Docket No. PP-230-2, Article 3, at p. 6 (2001) (emphasis added).

In previous discussions regarding the PARs, ITC has expressed its view that FERC lacks jurisdiction to order the transfer of functional control of the PARs, because the PARs are subject to DOE jurisdiction. However, a transfer of functional control no longer requires FERC approval under Section 203 after the decision in *Atlantic City Electric Company, et al. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002), and the Commission's subsequent *Guidance On Regional Transmission Organization And Independent System Operator Filing Requirements Under The Federal Power Act*, 104 FERC ¶ 61, 248 (2003).

Now that transfer of functional control is a matter of contract (i.e., pursuant to the TO Agreement) there is no legal barrier to ITC simply indicating its desire to have the

PARs entered into the ITC facilities list maintained by the Midwest ISO for facilities under its functional control. That would provide ITC with the same level of assurance afforded other Transmission Owning members regarding the operation of their facilities subject to, and within the limits imposed by, various regulatory and operating restrictions applicable to physical plant:

> By this Agreement, each of the Owners authorizes the Midwest ISO to exercise functional control over the operation of the Transmission System as necessary to effectuate transmission transactions administered by the Midwest ISO. Such control shall be exercised in accordance with Good Utility Practice and *shall conform to applicable reliability guidelines, policies, standards, rules, regulations, orders, license requirements* and all other requirements of the North American Electric Reliability Council, applicable regional reliability councils, or any successor organizations, each Owner's specific reliability requirements and operating guidelines, *and all applicable requirements of federal or state laws or regulatory authorities*.

Transmission Owners Agreement, Article Three, I. A. (emphasis added).

Thus, all restrictions applicable to the facilities that are the subject of the Presidential Permit must be observed by the Midwest ISO in performing its duties as the independent system operator, and a NERC registered reliability coordinator.

In the absence of functional control of these facilities it is unclear how transmission service transactions across the interface are completed, since the Midwest ISO has authority over, and schedules transmission service over, only those facilities under its functional control. This creates a legal gap between the point at which the Midwest ISO's functional control ends, and the point of interconnection with facilities controlled by IESO on the Canadian side of the interface.

Because it lacks the normal RTO authority over the PARs that comes with functional control, the Midwest ISO respectfully requests that the DOE clarify in its final order that the terms of Exhibit A are consistent with any permit limitations that may be imposed in PP-230, and that the Midwest ISO may implement the Operating Instruction with IESO for the safe and reliable operation of the PARs, as set forth in Exhibit A.

2. Authority of the Midwest ISO as Reliability Coordinator

While the characteristics of an Alternating Current system are suitably accommodating to permit the flow of energy across the B3N circuit despite the legal lacuna, an equally significant difficulty arises from the statement in ITC's petition that the facilities will be operated to comply with the "directives of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), the NERC-registered Reliability Coordinator *for the Interconnection Facilities*." ITC Request, p. 2 (emphasis added).

In a letter to the FERC dated August 26, 2004, ITC and the Midwest ISO informed the FERC that they had resolved their differences with regard to the ITC-IESO interface, in order to satisfy an outstanding NERC audit recommendation related to the 2003 Blackout. That letter stated that ITC "acknowledges the authority of the Midwest ISO, acting as the Reliability Coordinator for the International Transmission system, to direct any and all actions regarding the interface that are required or authorized by NERC Policy 9." Unfortunately, that letter predates the passage the Energy Policy Act of 2005, and the subsequent adoption of enforceable reliability standards, and it fails to allocate risks that may arise under the new penalty regime.

Under the Transmission Owners Agreement, consistent with Order No. 2000, the Midwest ISO is the Reliability Coordinator for those facilities, and only those facilities, transferred to its functional control: "The Midwest ISO is hereby designated and shall be the Security Coordinator[4] of the Transmission System for the Owners." TO Agreement, Appendix E, V.A.3. The term "Transmission System" is defined as the "transmission facilities of the Owners which are committed to the operation of the Midwest ISO by this Agreement." Transmission Owners Agreement, Article One, I.M.

The Midwest ISO Tariff accommodates independent transmission system ownership through Appendix I. This arrangement permits an independent system owner, such as ITC, to retain certain authority for the operation and planning of its system that would normally be done by the RTO. Although ITC and the Midwest ISO entered into an Appendix I Agreement dated August 31, 2001, and that agreement was approved by FERC, the definitions and operative provisions of that agreement reach the same point—the Midwest ISO is the Reliability Coordinator only for those facilities which ITC has transferred to its functional control.

Schedule 2 of the Appendix I Agreement provides: "MISO is hereby designated and shall be the Security Coordinator for the International System." The term "International System" is a defined term which "shall have the meaning set forth in Section 4.1.2 hereof." Section 4.1.2 reads:

> MISO shall promptly notify International in writing of the satisfaction of all applicable legal requirements necessary for MISO to assume functional control of the Facilities. On the fifth day following the date of such notice by MISO (the "Control Date"), *International will transfer and MISO shall assume functional control of the Facilities constituting the International transmission system (the "International System")*, consistent with Article Two, Section X.B of the MISO Agreement. MISO will thereafter exercise such functional control over the Facilities and the International System consistent with its responsibilities under Article Three, Section I.A of the MISO Agreement.

Appendix I Agreement (emphasis added).

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[4] The term "Security Coordinator" was changed by the industry to "Reliability Coordinator" following the terrorist attacks of September 11, 2001 to avoid possible confusion with Homeland Security activities. The functions are the same.

Because ITC has not transferred functional control of the facilities that are the subject of this Presidential Permit, those facilities are not within the definition of the "International System" and there is no clear legal relationship between those facilities and the Midwest ISO. The 2004 joint letter to FERC states only that ITC will operate the PARS "to comply with" directives issued by the Reliability Coordinator. It does not address the legal status of those facilities or allocate liability for negligence.

In 2008 the Midwest ISO obtained FERC approval of Tariff amendments to permit it to act as the Reliability Coordinator for third party contract customers, subject to the terms and conditions set forth in the Midwest ISO Tariff—i.e., the same provisions governing liability, indemnity, force majeure and other provisions applicable to Transmission Owning members that have transferred functional control of their facilities. These Tariff provisions are essential to implement the FERC approved allocation of risk between the Midwest ISO and its Tariff customers.

The Midwest ISO respectfully requests that any amended permit issued in this docket include one of the following conditions: (1) that ITC transfer functional control of the interface facilities to the Midwest ISO, or (2) that ITC execute a Service Agreement KK-1 to provide for Reliability Coordination services on the same non-discriminatory terms and conditions applicable to all other facilities and customers of the Midwest ISO, or (3) that ITC agree in writing that the facilities governed by PP-230 are deemed to be a part of the "International System" (even though not transferred to the Midwest ISO's functional control) and thus subject to the hold harmless, indemnity, and other provisions of the 2001 Appendix I Agreement between ITC and the Midwest ISO.

Of the three, the Midwest ISO respectfully requests the DOE to strongly consider the first. Transferring functional control of these international facilities, under the terms and conditions of the 2001 Appendix I Agreement, appears to be consistent with the agency's understanding of their status in the 2003 Order in Docket No. PP-230-3. It is consistent with current FERC policy that does not require FERC approval for such transfers; it clarifies the rights duties and obligations of the parties consistent with regard to Reliability Coordination; and it eliminates the legal gap between the US end of the B3N circuit, and their point of interconnection with the Canadian facilities of the IESO for the purpose of granting transmission service.[5]

The implementation of enforceable reliability standards and possible financial penalties has created significant risks for each owner, operator and user of the Bulk Electric System. Absent transfer of functional control, or application for service under Module F of the Tariff, or the protections of indemnity, there is no justification for ITC to unilaterally shift these risks to the Midwest ISO, effectively obtaining terms and conditions that are preferential.

D. Conclusion

The Midwest ISO strongly urges the DOE to approve the ITC request to amend PP-230 to permit the return to service of the B3N circuit and Phase Angle Regulators. The evolution of RTOs and the significant changes that have occurred in the industry in just the last few years have created areas of confusion regarding the operation of facilities

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[5] This also would eliminate a barrier to complying with Section 11.6 of the Appendix I Agreement. That section obligated Midwest ISO to develop a tariff proposal to compensate ITC for parallel flows on the interface. Because Midwest ISO's tariff authority extends only to facilities under its functional control, there was no practical way to establish standing at FERC to do so. The Midwest ISO agrees with the premise of Section 11.6 that some form of compensation would be appropriate, given the lack of incentive for IESO to join a congestion management process that would otherwise control these flows. *See* Answer of the Midwest ISO to Comments of NEMA, FERC Docket No. ER08-1281-000, August 15, 2008.

which are part of the Bulk Electric System, but which are also used to export electric energy across international borders. Because the trend following the adoption of enforceable reliability standards is to eliminate all grey areas with regard to the Bulk Electric System, the Midwest ISO respectfully requests the DOE to clarify in its final order the issues raised by the Midwest ISO in these comments.

Respectfully submitted,

Gregory A. Troxell
Assistant General Counsel
Midwest Independent Transmission
System Operator, Inc.
720 City Center Drive
Carmel, Indiana 46032

March 12, 2009

EXHIBIT A

3.0 MAXIMUM NET SCHEDULED INTERCHANGE

3.1 The maximum Net Scheduled Interchange between the Midwest ISO and IESO on the Michigan-Ontario interface shall follow the NERC Reliability Standard INT-003, as amended.

4.0 REACTIVE TRANSFER

4.1 Reactive transfers on the Michigan-Ontario interface shall be arranged in accordance with instruction MISO-IESO-C03 Michigan-Ontario Interface Voltage Control Procedure.

5.0 PRINCIPLES FOR UTILIZING THE PHASE ANGLE REGULATING TRANSFORMERS

5.1 The following sets forth operating principles for the Phase Angle Regulator ("PAR") transformers installed as part of the Michigan-Ontario Interconnection Facilities. Phase Angle Regulators shall be operated primarily to control power flow circulating through the electrical systems of Ontario and Michigan while protecting respective Michigan and Ontario transmission facilities. Control strategies for the operation of such facilities shall recognize the following objectives, in descending order of priority:

a) The resolution of declared emergency operating situations or conditions affecting Ontario or Michigan;

b) The resolution of a declared emergency operating state, for an entity outside of Ontario or Michigan, that will result in the necessity of shedding firm customer load, in accordance with section 8.1. In these circumstances, the PARs may be adjusted to assist the affected system to the extent practical, without creating additional security violations. The PARs shall be considered as one of the control actions available to assist the affected system. The type of assistance shall be agreed upon by MISO and the IESO.

c) When effective, relieve constraints within the MISO Transmission Owners' area of Michigan, or within Ontario.

d) Facilitate scheduled transfers between the areas in which MISO and IESO operate, by operating the PARs such that the flow over the Michigan-Ontario interface matches, within practical considerations, the net scheduled interchange over the interface.

In applying each of the above principles, if there are conflicting requirements for adjusting the PAR tap positions, the request that directs the flow towards the net schedule shall take priority.

It is recognized that the above principles remain valid but will be difficult to achieve when an in-line PAR is out-of-service or by-passed.

5.2 In the day-ahead(s) or future operational planning time frame, forecasts of tie line flows shall account for any anticipated uncontrolled loop flows. The Parties agree to discuss day-ahead operations and share their assumptions when determining these expected flows.

In the operating day time frame, the markets shall be scheduled accounting for expected uncontrolled loop flows after full utilization of PARs control capability and implementation of TLR3a.

5.3 The parties that participate in and consent to the adjustments of the PARs are defined in Appendix B.

6.0 COMMUNICATIONS

Communications will be via a telephone conference ("blast call"), as outlined in Appendix B, Table B.1. ITC, Midwest ISO, or IESO may initiate a blast call. Any party may initiate a call if flows are causing or are anticipated to cause a reliability or operational concern.

6.1 Real-Time Operations

MISO and IESO shall mutually agree to operate the PARs in order to meet the Operating Principles contained in section 5.1. All parties identified in Appendix B will normally be included in these discussions.

6.2 Scheduling:

The IESO and MISO shall jointly approve and confirm the MISO-IESO schedules (on the Michigan interface) prior to schedule implementation.

6.3 Setting Target Flow:

All parties shall discuss and agree on target flow for the interface and the individual circuits (J5D, L4D, L51D, B3N). This will normally be done during a blast call at 15 minutes prior to the dispatch hour.

6.4 Third Party Communications:

Interchange Distribution Calculator (IDC)

If the parties determine that PAR control is unavailable or ineffective, the IESO shall make the appropriate changes in the IDC.

Reliability Coordinator Information System (RCIS)

If the parties determine that PAR control is unavailable or ineffective, the IESO shall make the appropriate notifications via the RCIS.

7.0 NORMAL OPERATING STATE

PAR changes shall normally occur once an hour based on a best estimate of the next hour target flows to meet the agreed upon schedule. There should be no consideration of a dead band when determining target flows.

Under normal operating conditions, intra hour changes to target flows will not be implemented. Intra hour changes will normally only be implemented to achieve the principles identified in section 5.1 (a), 5.1 (b), or 5.1 (c).

To the extent possible given equipment or other limitations, and consistent with the principles outlined in Section 5.1, the PARs shall be adjusted coincident with the normal interchange schedule ramping period (i.e. 5 minutes prior to the hour to 5 minutes after the hour).

7.1 Scheduling

Consistent with Section 5.1, the interface capability should normally assume flow equals schedule. During periods when the ability to fully control the interface flow is unavailable (either due to equipment outages or circulation in excess of the ability of the PARs to control) the interface flow should be managed to maximise the transfer capability, provided there is no adverse impact on Interconnection reliability.

Normal scheduling limits will reflect all known restrictions, outages or deratings to equipment that form part of the interconnection as per operating agreements. Normal scheduling limits include an allowance for normal variations in flow.

7.2 IDC/RCIS Inputs

The IDC flag for the control of the Michigan-Ontario interface should be set to reflect the ability of the PARs to control actual flow to scheduled flow. The flag should be set to non-regulating whenever the expected capability of the PARs to do so is in excess of 200 MW.

Whenever possible, this flag should be set in sufficient time to allow other RCs to understand the impact of the PARs and incorporate those impacts on their operation (i.e. TLRs).

Whenever the flag is changed in IDC, an RCIS message should be sent using the free form section to advise the Eastern Interconnection RCs of the change in control of the Michigan-Ontario PARs.

8.0 ABNORMAL OPERATING STATE

For the purposes of this instruction an abnormal operating state is considered to exist when the conditions identified in Section 5.1 (a), 5.1 (b), or 5.1 (c) exist or are expected to exist.

8.1 PAR Operations

The PARs should be adjusted to assist in relieving IROL/SOL violations, including moving away from scheduled flows if such action contributes to relieving the IROL/SOL violations.

If and when sufficient relief has been effected, or when the limit violation has been corrected such that off-schedule PAR operation is no longer required, the PARs shall be re-adjusted such that the flow of energy over the Michigan-Ontario interface matches, within practical considerations, the net scheduled interchange over the interface.

It is acceptable to change the target flow on a single line to address an IROL/SOL violation (i.e. tap J5D) without moving the remaining PARs.

The PARs may be operated to assist an entity outside of Michigan and Ontario to avoid shedding firm load, under the following conditions:

1. The entity has taken all mitigating steps up to, but not including, shedding of firm load.

2. PAR operation being considered to assist another entity will not result in firm load shedding in Michigan or Ontario,

3. The entity makes every available effort following the implementation of the PAR operation modification to quickly restore their system to a position such that normal flow to schedule PAR operation has resumed.

9.0 DISPUTE RESOLUTION – REAL-TIME OPERATIONS

The Parties agree to make reasonable attempts to accommodate requested tap changes, consistent with the Operating Principles outlined in 5.1. In the event that parties are unable to agree on an appropriate action in real-time, shift staff should not spend an inordinate amount of time discussing conflicts.

In the event of a disagreement, the tap position that would result in a flow equal to schedule should be the default position, unless this will cause a reliability concern. On-shift staff should make reasonable attempts to accommodate requested tap changes unless the proposed action will cause undue equipment or safety concerns.

The dispute will be reviewed by the management of parties during the next business day. If necessary, changes will be implemented to mitigate future similar disputes.

10.0 TERMINATION, REPLACEMENT OR REVISION OF OPERATING INSTRUCTION

This Operating Instruction shall remain in full force for the period as specified above unless terminated in advance by mutual agreement of the Parties or cancelled by either Party by sending a 30-day prior written notice to the other Party.

Approved by the Coordination Committee:

MidwestISO
Energizing the Heartland

____

Dated: ______________________________

ieso
Power to Ontario.
On Demand.

____

Dated: ______________________________

APPENDIX A:

APPENDIX B:

Communications and Operating Procedures

Table B.1:

Initiator (tap change):	**IESO**	**MISO**	**ITC - TO**
Originating entity contacts (single call):	MISO ITC-TO ITC-BA (MECS) HONI	IESO ITC-TO ITC-BA (MECS) HONI	IESO MISO ITC-BA (MECS) HONI

<u>Contact Information:</u>

IESO - Markets (Schedules)
- System (Reliability)

MISO - Reliability

ITC-TO - Senior Transmission System Coordinator

ITC-BA (MECS) - Senior BA Controller

Hydro One Networks - Sector 1 Controller

<u>Day-Ahead Planning/Scheduling (not included in Real-Time Blast Call):</u>

IESO -Market Forecasts & Integration

MISO -Operations Engineering
- Scheduling

Attachment B

Copy of the Midwest ISO's October 5, 2010 presentation the NERC Interchange Distribution Calculator Working Group titled *Modeling MI-ONT PARS in IDC*

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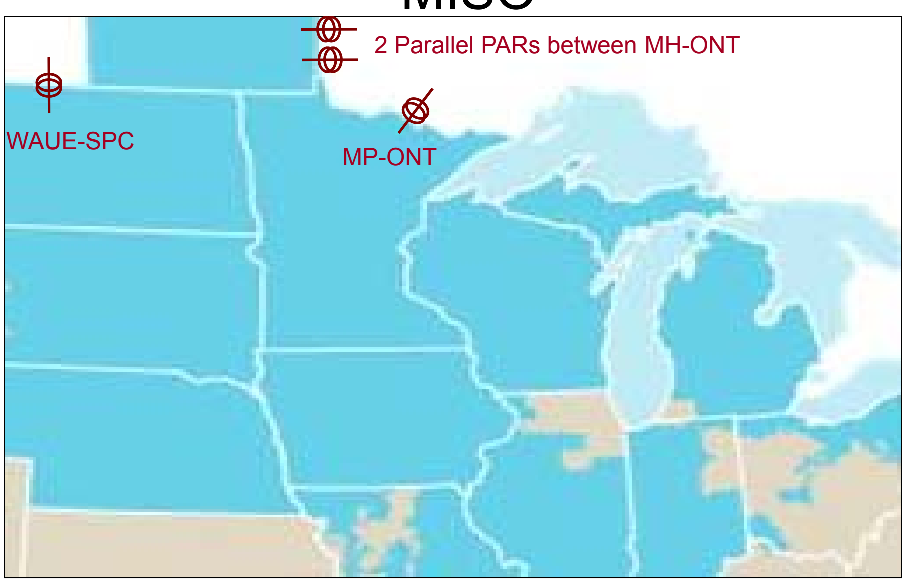
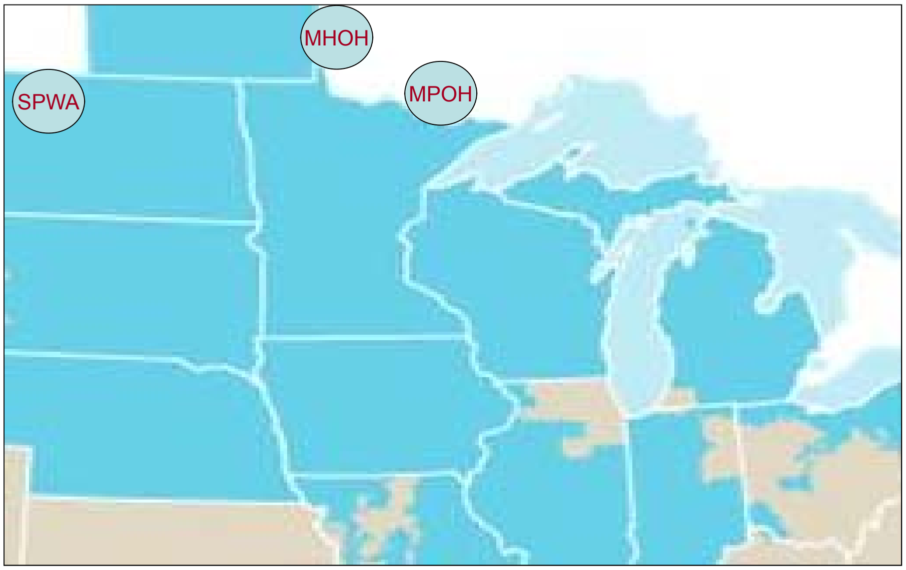
Modeling MI-ONT PARs in IDC

NERC ORS Meeting
September 22, 2010

Regulated Phase Shifters within MISO



Current Modeling in IDC



Future IDC Model

- MI-ONT Phase Shifters
  - Expected to be controlled in Q4 of 2010
  - Regulated operation of Interface by setting phase shifter taps at the beginning of the hour based on hour ahead forecast
    - » Objective is to have actual flow equal to scheduled flow
    - » Conditions can change in real-time and there may be some circulation flow in real-time
  - No intra-hour tap adjustments to address the circulation flows

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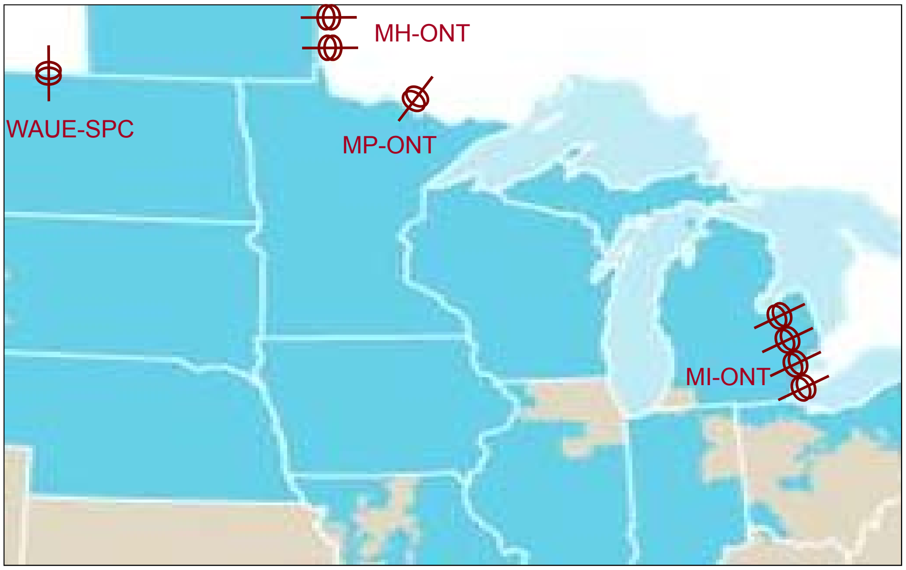
Regulated Phase Shifters within MISO



Changes in IDC Model

- Phase Shifter/Interface Status:
  - Currently, IDC allows to set status of each of the 4 PARs individually
  - Change IDC to have a single status (flag) for an Interface that resets all 4 PARs
- Regulate Mode:
  - Tags with "MI-ONT" as POR/POD will 100% flow across the interface or phase shifters
    - » Flow over the 4 PARs that form the interface will be based on the pre-determined percentages and will not be updated over time except during outage of one or more segments of PARs.
    - » Pseudo CAs will be used to determine impact on other FGs
  - Tags not using "MI-ONT" as POR/POD and Market Flows (GTL) will flow across the rest of the network (open circuit)

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Changes in IDC Model

- Non-Regulate Mode:
  - Equivalent to max tap/min tap position
  - Non-regulate status for each of the four PARs (Interface)
    - One PAR will hit a max/min tap position while the other 3 will still have tap range available (minimize the circulation flow between the four PARs)
  - Tags with "MI-ONT" as POR/POD will 100% flow across the interface or phase shifters
  - Tags not using "MI-ONT" as POR/POD and Market Flows (GTL) will have some portion across the interface and the remainder on the rest of the network (free flowing)
    - Based on the impedance of PARs relative to the rest of the system
- By-Pass Mode:
  - PARs are on neutral tap and not regulating

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Examples

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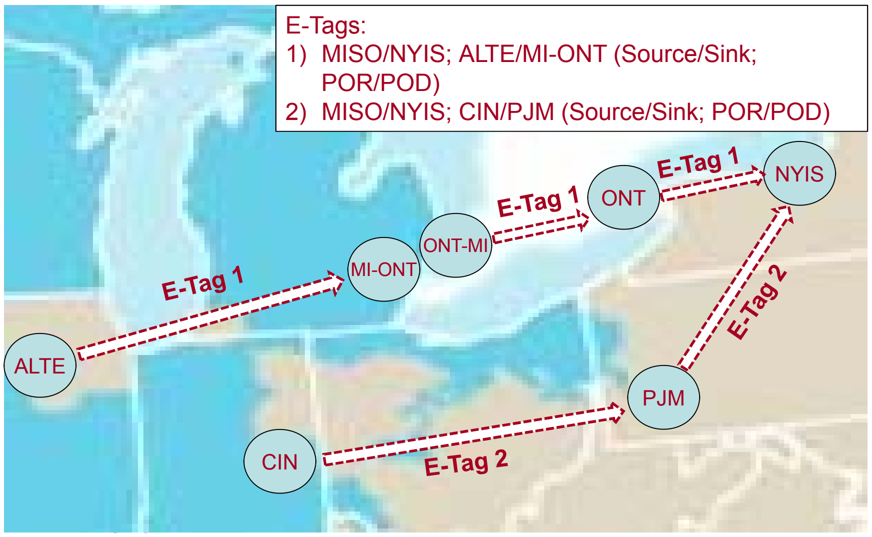
Example for Regulating Mode



Example for Regulating Mode (contd.)

- E-Tag 1 will be seen by IDC as flowing over Michigan-Ontario phase shifters or Interface FG # 9084
- IDC will use pseudo CAs "MI-ONT" and "ONT-MI" to calculate impact of E-Tag 1 on all FGs except Interface FGs # 9084 and 9159
- IDC will calculate impact of E-Tag 2 on all the FGs as if Michigan-Ontario Interface is open circuit
- MISO/PJM will calculate Market Flows by modeling Michigan-Ontario Interface as open-circuit
  - MISO/PJM Market Flows on IESO and NYIS FGs would be 0

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Example for Regulating Mode (contd.)

- For TLR on FGs # 9084 and 9159 (very unlikely while in Regulating Mode)
  - » E-Tag 1 will have 100% (or -100%) impact on the interface flowgates
  - » All other Tags will have 0 % impact on the interface flowgates
- For TLR on any other flowgate in the system, IDC will assume the interface is an open circuit and calculate impacts of E-Tags and Market Flows (GTL) on the congested flowgate accordingly
  - » E-Tag 1 using Pseudo CAs
  - » E-Tag 2 and Market Flows as if interface is an open circuit

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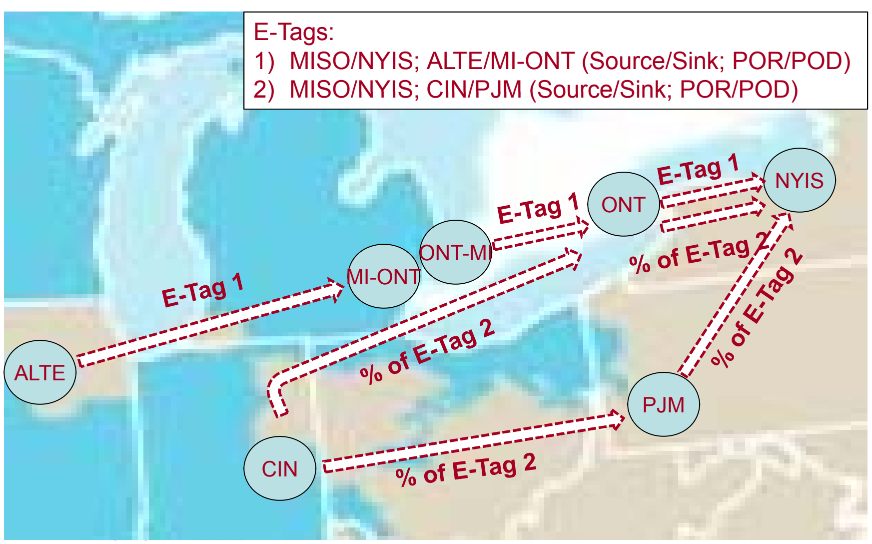
Example for Non-Regulating Mode



Example for Non-Regulating Mode (contd.)

- E-Tag 1 will be seen by IDC as flowing over Michigan-Ontario phase shifters or Interface FG # 9084
- IDC will use pseudo CAs “MI-ONT” and “ONT-MI” to calculate impact of E-Tag 1 on all FGs except Interface FGs # 9084 and 9159
  - » E-Tag 1 will have 100% impact on Interface FGs # 9084 and 9159
- IDC will calculate impact of E-Tag 2 on all the FGs as if Michigan-Ontario Interface is free flowing
  - » Portion of E-Tag 2 will flow through the Interface and remaining will flow through the rest of the network depending on impedance of PARs relative to the AC system
- MISO/PJM will calculate Market Flows by modeling PARs at max tap or min tap, where a portion will go through the Interface and remaining through the rest of the network

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Example for Non-Regulating Mode (contd.)

- For TLR on FGs # 9084 or 9159, IDC will assume 100% of impact from E-tag 1 on the congested flowgate and portion of all other E-Tags and market flow through the interface
- For TLR on any other flowgate in the system, IDC will assume the interface is a free flowing system and calculate impacts of E-Tags and Market Flows (GTL) on the congested flowgate accordingly
  - » E-Tag 1 using Pseudo CAs
  - » E-Tag 2 and Market Flows as if interface is free flowing

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Benefits of PAR Operations

- Assume PARs have ability to push back a maximum of 600 MW of parallel flow on the interface when fully regulating.
- The following two scenarios demonstrate the ability of the PARs to push back 600 MW when in regulate mode and when in non-regulate mode:

<u>Scenario 1-PARs in Regulate Mode</u>

- Scheduled flow across interface 600 MW
- Potential parallel flows across interface 600 MW
- Potential total flow across interface (if not reg) 1200 MW
- Source of parallel flows:
  - Tag impacts 300 MW
  - Market flow impacts 300 MW
- PARs are in regulate mode pushing back 600 MW. Actual flow across interface is 600 MW.

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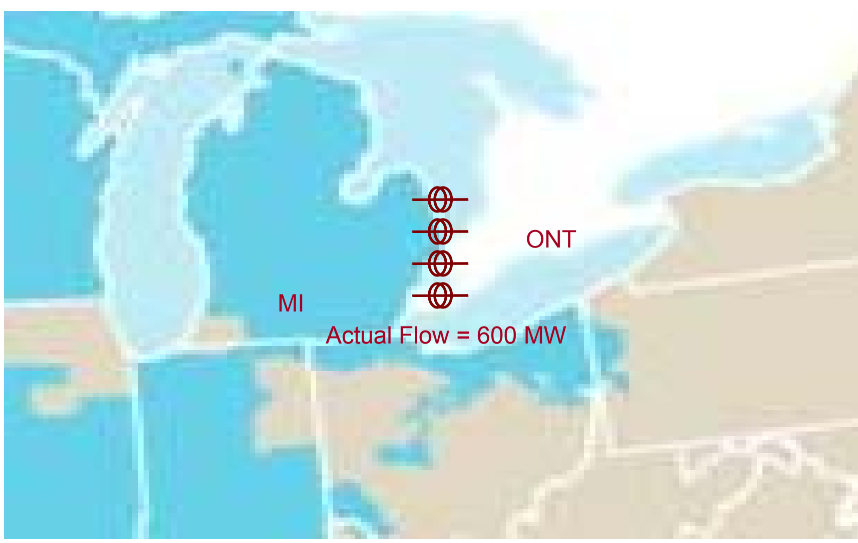
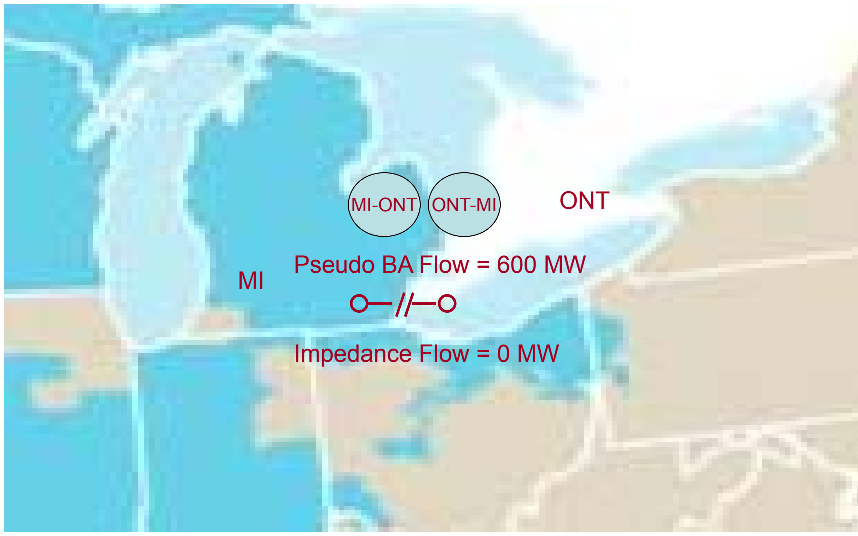
Scenario 1- Actual Interface Flow



Scenario 1-IDC Modeled Interface Flow



Benefits of PAR Operations cont.

- IDC shows 100% of the 600 MW flowing across the interface. Remaining tag impacts and market flow impacts see this as an open interface.
- If TLR called, would have 600 MW impacts across the interface based on pseudo BAs. The remaining 600 MW of potential parallel flows at 0 MW (see an open interface).
- If call TLR on an IESO or NYISO flowgate, MISO and PJM market flows appear to be 0 MW and tag impacts (other than the 600 MW) appear to be 0 MW.

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Benefits of PAR Operations cont.

Scenario 2-PARs in Non-Regulate Mode

- Scheduled flow across interface 600 MW
- Potential parallel flows across interface 625 MW
- Potential total flow across interface (if not reg) 1225 MW
- Source of parallel flows:
  - Tag impacts 300 MW
  - Market flow impacts 325 MW
- PARs are now in non-regulate mode but continue to push back 600 MW. Actual flow across interface is 625 MW.
- IDC shows 100% of the 600 MW flowing across the interface. The remaining tag impacts and market flow impacts see this as a free flowing system based on the impedance of the interface relative to the impedance of the remainder of the AC system.

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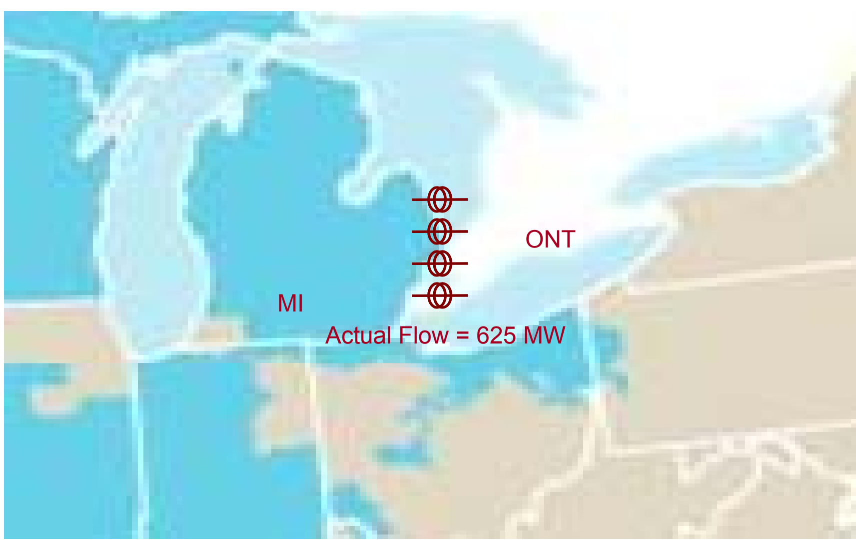
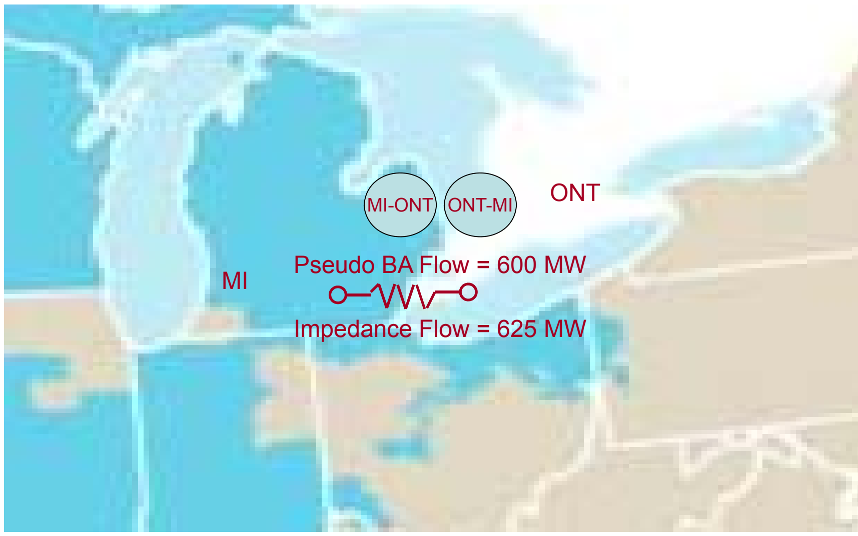
Scenario 2- Actual Interface Flow



Scenario 2-IDC Modeled Interface Flow



Benefits of PAR Operations cont.

- A question has been raised on who should get the benefits of the PARs pushing back 600 MW when fully regulating (this is the difference between the actual parallel flow and the IDC parallel flow when PARs has status of non-regulate).
  - In Scenario 2, the 600 MW of benefits are not being assigned to anyone. This is why we see the large difference between actual parallel flow and IDC parallel flow.
  - An alternate approach would assign the 600 MW of benefit to the parties responsible for the PARs (IESO & MISO). This alternative would remove up to 600 MW of MISO market flows and IESO GTL flows from inclusion in impacts subject to TLR curtailments. Since MISO is recommending regional cost sharing of the PARs, this alternative is not being pursued.

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Benefits of PAR Operations cont.

- Another question has been raised whether the 600 MW scheduled across the interface should continue to assume 100% flows across the interface when PAR is fully regulating (PAR has status of non-regulate). The current design of the IDC removes the pseudo BA treatment and has the entire 600 MW use a response factor based on the impedance of the interface relative to the rest of the AC network to set the flow across the interface. We have the following response to this question:
  - We agree this is the acceptable when the PAR status is by-pass. This is effectively how the interface is operated today.
  - We do not agree it is acceptable when the PAR status is non-regulate. The PARs continue to regulate at max tap such that the actual flow consists of scheduled flow plus some component of parallel flow

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Benefits of PAR Operations cont.

- The schedules across the interface are from reservations for transmission service purchased across the interface as opposed to parallel flows from third parties that have no rights on the interface.
- If the schedules across the interface were to get combined with the rest of the tags and market flows, these flows would go from 0 MW to 1081 MW (assuming the impedance causes 80% of the scheduled flow to go across the interface) after 1 MW of parallel flow appears on the interface. This will cause volatility issues in the IDC where all schedules get cut and all schedules are reloaded when there is a 1 MW swing in parallel flows.

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Benefits of PAR Operations cont.

- Under this proposed treatment, all of the potential parallel flows now appear as if flowing across the interface. Although actual flows only increased 25 MW, the IDC now shows 600 MW of scheduled flows across the interface plus 625 MW of parallel flows across the interface.
- If call TLR on an IESO or NYISO flowgate, MISO and PJM market flow impacts appear to be 325 MW and tag impacts (other than the 600 MW) appear to be 300 MW.
- Even though the actual flow across the interface only increased 25 MW, the IDC shows the full amount of parallel flows (625 MW) available to manage congestion on IESO and NYISO flowgates.

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Modeling MI-ONT PARs in IDC

- Questions?

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Attachment C

Copy of the NYISO's October 5, 2010 presentation to the NERC Interchange Distribution Calculator Working Group titled *Modeling MI-ONT PARS in IDC*

Modeling MI-ONT PARs in IDC

IDC Working Group
Oct 5-7
David Mahlmann

Draft for Discussion

Concerns with MISOs Proposal

- NYISO cannot support the MISO proposal because it
  - *Proposes to inflexibly pre-determine how system reliability can be protected, that cannot and will not account for real-time system conditions*
  - *Gives both firm and non-firm transactions scheduled at the OH/MI interface an absolute priority over all other transactions and GTL impacts, even when the PARs are not adequately maintaining scheduled flow*
  - *Could adversely affect system reliability*
- MISO's presentation explicitly recognizes that implementing the method it proposes will result in uncorrected Lake Erie circulation, but ignores the potential reliability impact

Concerns with MISOs Proposal

- The proposal will permit circulation that **cannot** be corrected when MISO determines the PAR settings and declares the PARs to be regulating at the top of the hour, even when
  - *The PAR schedule that is determined for the hour fails to accurately match flow to schedules over the interface*
  - *Real-time events like line outages, significant generator outages, or dispatch/load variations occur*
  - *MISO-PJM implement significant quarter-hour transaction changes*
  - *A "counterflow" transaction that was projected to provide counter pressure when the fixed angle phase shift was calculated is removed or curtailed*
  - *TLR actions that impact relative power angles across the Interconnection are taken, causing flow across the fixed angle phase shifters*

Issues with the MISO Proposal

- Even when the top-of-the-hour determination recognizes that the PARs are not regulating
  - MISO proposes to give both firm and non-firm transactions scheduled at the OH/MI interface an absolute priority over all other transactions and GTL impacts (they will not be available in the IDC for removal/curtailment)
  - For example when the PARs are not regulating, NYISO will be able to use the TLR process to remove firm MISO GTL service, or MISO to PJM transactions to address a New York constraint, but will have no ability to remove non-firm transactions scheduled over the OH/MI interface
    - Not even when the non-firm transaction has a larger impact on the New York constraint than the firm GTL
    - Non-firm transmission service over the OH/MI interface will be more "firm" than firm transmission service that does not cross the interface

Reliability Risk Example

OH/MI PAR scheduled fixed for the hour and the PARs are determined to be "regulating"

Top of hour	*1000 MW actual*	*1000 MW Sched*
+ 10 min	*1000 MW actual*	*1000 MW Sched*
+ 20 min	*0 MW actual*	*1000 MW Sched*
+ 30 min	*-500 MW actual*	*1000 MW Sched*

- *1500 MW change in actual flow since the top of the hour, PARs are fixed and will not be moved to address subsequent changes in system conditions*
- *NYISO has no ability to TLR when PARs are declared "regulating"*
- *The NYISO requires the ability to apply TLR to all transactions to preserve system reliability when circulation is observed*

NYISO Proposal – 2 Stage TLR 9 (1of2)

- NYISO proposes to protect transactions scheduled over the OH/MI PARs when transaction flows conform to schedules (plus an agreed upon bandwidth), but to permit TLR actions to remove unscheduled flows
- Method of determining when PARs are not controlling should be changed from a "taps at limit" flag to a "flow outside schedule plus allowed bandwidth" flag.

Draft for Discussion

NYISO Proposal – 2 Stage TLR 9 (2of2)

- A the time the TLR is initiated, and throughout the TLR process, the IESO-MICH projected flows should be compared to the IESO-MICH projected schedule
- Whenever the IESO-MICH projected flows are outside the schedule plus an agreed-upon bandwidth, ONT-MI PARs modeled as non-controlling and all transactions will be subject to curtailment, as they are today
  - *with the additional monitoring of the cumulative effect of the curtailments on the IESO-MICH projected flows described below*
- If the requested relief has not been met when the projected IESO-MICH flows are brought back within schedule plus bandwidth, then
  - *Pause the continued TLR computations,*
  - *Re-compute the shifts with ONT-MI PARs modeled as controlling*
  - *Continue the TLR calculations with the new shift factor until the necessary relief is obtained*

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Draft for Discussion

Advantages of NYISO Proposal

- Promotes system reliability with tools to control circulation over a wide range of system conditions
- Provides uniform open access treatment when the MI-ONT flows are uncontrolled, i.e. when portions of MI-ONT transactions are circulating outside the ties.
- Conforms with the intention to operate PARs once an hour
- Shields MISO-IESO transactions from TLR curtailments when the interface flow is on schedule.

8

The New York Independent System Operator (NYISO) is a not-for-profit corporation that began operations in 1999. The NYISO operates New York's bulk electricity grid, administers the state's wholesale electricity markets, and provides comprehensive reliability planning for state's bulk electricity system.

www.nyiso.com

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon each person designated on the official service list for the captioned proceeding, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 17th day of November, 2010, at Rensselaer, New York.

/s/ Alex M. Schnell

Alex M. Schnell
New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, New York 12144
Ph: 518-356-8707