STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to integrated resource and distribution plans.	))))	Case No. U-20633

COMMENTS OF THE
ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

I. INTRODUCTION

During the January 19, 2020 stakeholder meeting in this proceeding Michigan Public Service Commission ("Commission") Staff requested feedback regarding a number of questions concerning transmission planning and the modeling of transmission constraints in integrated resource plans ("IRPs"). The Association of Businesses Advocating Tariff Equity ("ABATE") provides its responses to those questions, as well as its general comments on transmission planning in Michigan, below.

II. COMMENTS

A. What should be changed within the transmission planning section of the filing requirements?

- **Are there specific changes that stakeholders would recommend based upon the conversation today that would clarify, add, or change the existing filing requirements?**
- **What documentation would stakeholders find helpful in the filing?**

In its October 28 comments submitted in this proceeding ABATE provided the following general comment regarding transmission planning and the Michigan Integrated Resource Planning Parameters ("MIRPP"):

Transmission planning should be seen as a source for alternative resources to obviate additional generation.

The MIRPP requires capacity import and export limits in IRP models resulting from the most current and planned transmission system topology and requires utilities consider including transmission assumptions in the IRP portfolio, such as the impact of transmission and non-transmission alternatives to the extent possible. In addition to these requirements, externalities outside the "energy box" which could represent diverse resources must include consideration of the extent to which increased transmission capacity can allow for alternative sources of energy to substitute for centralized generation. Such considerations should also address to what extent increased transmission capacity can serve to address other grid planning issues, such as renewable intermittency, decentralization, and resilience. Expanding the potential role of transmission capacity can further curb potential capital expenditures.

In other words, the filing requirements should require IRPs consider more than just restraints resulting from transmission import and export limits, they should consider where potential additional transmission and non-transmission alternative resources could allow for alternative sources of energy to substitute for centralized generation and aid in resolving other grid planning issues. Stated another way, transmission resources should be considered as an answer to address grid issues, not just a limiting factor on resource planning. Section X.11 of the MIRPP should therefore be expanded to encourage inclusion of these resources as a method of avoiding additional generation investment and addressing related grid concerns. Documentation on the feasibility of using additional transmission or non-transmission alternatives to address these issues, to the extent possible, would be helpful.

B. How should transmission constraints be modeled in an IRP?

a. How should the transmission import capability forecast be developed given that the CIL and CEL are historically volatile?

b. Should CIL and CEL be used in modeling at all? Or should another measure be the transmission constraint?

c. How should energy and capacity availability in other zones be modeled and how should the utilities acquire this information? How is this done in a way that doesn't create undue burden or an impossible task for utilities filing an IRP? Should out of state

resources be allowed to enter RFPs provided they have firm transmission rights? Given the LCR has been a limiting agent in the last MISO year does it make sense to consider out of state resources?

Regarding the latter of Staff's questions on this issue, out of state resources should be allowed to enter RFPs and out of state resources should be considered so that IRPs may include the fullest possible perspective on viable resource availability and cost. The potential utility of reliable, lowest-cost resources out of state is instructive to determine the most efficient and cost-effective method of meeting demand and capacity needs. These resources should not be excluded when they could provide necessary services to a utility and its customers at costs below those potentially circumscribed by the requirements of a local clearing requirement.

C. Additional comments.

In addition to the comments provided above, Staff should consider a broader analysis of transmission resources and planning beyond its inclusion in the current IRP process. In the context of utility IRPs the filed transmission assumptions are guided by those utilities and necessarily colored by utility interests and incentives. Further, through utility-filed IRPs transmission resources and planning are considered in multiple utility-specific and thus incomplete perspectives. To develop optimal analyses and planning regarding the dynamic nature of this issue Staff should also pursue a more comprehensive state-level process for transmission planning in which stakeholders (including utilities) are permitted to provide input. The stakeholder inputs and results of this more expansive planning process can be then integrated into utility generation resource and distribution planning.

The general structure of this process should entail a Staff-led planning effort to develop a planning framework including the following elements:

- Establish transmission-related goals in the context of the IRP process (e.g. reliability, generation resources, costs, timeframes);

- Identify transmission planning constraints (e.g. existing assets, capacities, characteristics, etc. as well as likely customer changes over time with regard to loads, generation resources, etc.);

- Identify alternatives to reach goals within constraints (i.e. modeling);

  - Central generation options;

  - Transmission options;

  - Customer incentive options (e.g. demand response, pricing, etc.);

- Evaluation of options (the Electric Power Research Institute ("EPRI")'s presentation at the January 19 meeting addressing incorporating risk in transmission planning provided a good framework for planning and project evaluation);

- Options selected based on cost and risk (again, the approach outlined by EPRI for risk-based transmission project evaluation and selection is reasonable and advisable).

Staff should ultimately develop a strawman proposal for this process in which the elements above are discussed, stakeholder input is provided, and Staff recommendations are determined. Such an approach would provide a valuable forum and method for cost-effective and forward-looking transmission resource planning, the inputs and results of which could then be incorporated into the broader generation resource and distribution planning process.

III. CONCLUSION

Pursuant to Staff's solicitation of feedback and for the reasons set forth herein, ABATE recommends Staff consider and incorporate the issues and points raised above into this stakeholder proceeding.

Respectfully submitted,

CLARK HILL PLC

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Date: February 1, 2021

02/01/2021

Comments of Consumers Energy Company
in the Integration of Resource/Distribution/Transmission Planning Workgroup
Session Six Feedback Request

Dear Ms. Rogers,

Thank you for the opportunity to provide comments on the feedback that Staff solicited during the sixth Advanced Planning stakeholder workgroup.

The Company would like to share the following considerations on Staff's questions:

1) **How should the transmission import capability forecast be developed given that the CIL and CEL are historically volatile?**

   The Company recommends an annual study of the 5-, 10-, and 15-year outlook of the Zone 7 CIL/CEL. Ideally, the study would be a refresh of the Michigan Capacity Import/Export Limit Expansion Study that MISO is currently performing at the request of MPSC Staff. MISO, as the RTO, is best suited to perform the annual study. The annual study should use an open stakeholder process.

2) **Should CIL and CEL be used in modeling at all? Or should another measure be the transmission constraint?**

   The Company believes that CIL and CEL should continue to be used to model the system capacity import and export constraints.

3) **How should energy and capacity availability in other zones be modeled and how should the utilities acquire this information? How is this done in a way that doesn't create undue burden or an impossible task for the utilities filing an IRP? Should out-of-state resources be allowed to enter RFPs provided they have firm transmission rights? Give the LCR has been a limiting agent in the last MISO year, does it make sense to consider out-of-state resources?**

   An accurate assessment of energy and capacity availability can only be accomplished through a Request for Proposal (RFP). Transmission analysis necessary to assess firm transmission rights can only be accomplished through a study at MISO. RFPs and transmission analysis represent a significant amount of work and would likely not lead to data useful to an IRP analysis. The Company recommends that inclusion of external resources in an IRP should be left to the discretion of the filing utility and not imposed as a requirement for filing an IRP.

4) <u>What should be changed within the transmission planning section of the filing requirements? Are there specific changes that stakeholders would recommend that would clarify, add, or change the existing filing requirements?</u>

The Company believes that determining what should be changed within the transmission planning section of the filing requirements requires dedicated time and a robust stakeholder process beyond Session Six and this feedback request.

In general, the Company recommends that consideration be given for further alignment of the transmission planning section of the filing requirements with existing MISO processes, such as MISO model development, MISO Transmission Expansion Planning (MTEP), and MISO Generator Interconnection and Retirement processes.

The Company also recommends that requirements for transmission owners be added to the transmission planning section of the filing requirements to ensure that the level of analysis being performed provides value to the utility's IRP filing. The value of the transmission analysis being performed to the utility's IRP filing is presently limited because, to our knowledge, the local transmission owner is not performing the same level of analysis as MISO performs in its MTEP, Generator Retirement, or Generator Interconnection processes. Transmission analysis is also very dependent on a specific set of assumptions, such as siting of new resources, that makes trying to perform transmission analysis in an iterative manner time and resource intensive further reducing its value.

5) <u>What documentation would be helpful for filing?</u>

The Company recommends requirements around required documentation for filing should not be prescriptive, and to allow the utility and local transmission owner to determine what documentation is most valuable to include in filing.

Respectfully submitted,
Consumers Energy Company

DTE Electric Response to Staff Questions Requested 01-19-2021

MI Power Grid– Advanced Planning Phase II

February 1, 2021

Overall Comments:

DTE Electric (DTE or Company) appreciates the effort of the Michigan Public Service Commission (MPSC), MPSC Staff (Staff) and all parties involved in this integrated planning collaborative. DTE views integrated resource planning as an opportunity to develop optimized plans to meet future system needs. Further, the results of an IRP analysis should position a utility to make directionally appropriate investment decisions for the benefit of customers.

The transmission IRP filing requirements as currently constructed contain open ended objectives that are challenging to comply with. The unique business structure in the State of Michigan where many utilities are not vertically integrated makes complying with the current requirements highly subjective and open to interpretation. Specifically, per the current requirements utilities shall:

- *"Include an analysis of potential new or upgraded electric transmission options for the utility"* despite having limited information regarding physical attributes of the transmission system and being unable to organize regional transmission planning

- *"Assess the need to construct new, or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options"* despite not knowing specific generation interconnection locations many years in the future and being unable to fully perform generator interconnection studies

- Include "*Any information provided by the transmission owner(s) indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system"* and include any information relating to import/export capabilities, facilitating PPAs, and efficiency enhancements among other items

These requirements impose a large burden on non-vertically integrated utilities to provide information they may have little insight into, are unable to obtain, or cannot thoughtfully incorporate into the IRP without enthusiastic and fully transparent participation from the transmission owner(s). These requirements further do not provide a concrete framework that governs the working relationship and expectations of each party involved in the IRP transmission analysis. Even with positive cooperation and engagement between parties, jurisdictional boundaries are challenging as the requirements only apply to utilities and not to transmission owners.

Traditional utilities have information on most physical aspects of the electric delivery system from the power source to the end-use customer. The State of Michigan is faced with a unique situation where significant elements of the electric grid are operated and controlled by separate entities. As revisions to the transmission analysis IRP filing requirements are contemplated and given the foregoing limitations, further recognition of this structural arrangement is needed to ensure optimal outcomes for customers. This could involve developing a framework that promotes use of the Pareto Principle where the transmission analysis performed seeks to identify the vital few issues that will result in the most significant cost drivers for customers. Finally, there must be recognition that the IRP cannot be a substitute for robust regional and sub-regional transmission planning that can only be efficiently coordinated and implemented by a regional transmission organization.

DTE Responses:

What should be changed within the transmission planning section of the filing requirement?

a. Are there specific changes that stakeholders would recommend based upon the conversation today that would clarify, add, or change the existing filing requirements?

In providing feedback to this question, DTE believes it would be useful to note some observations relating to the transmission analysis as part of integrated resource plans in the State of Michigan:

1) **There is significant information asymmetry between parties corresponding to the portions of the system within their functional control.**
    - For example, only transmission owners have detailed information about ratings on specific transmission facilities such as conductors, breakers, and switches. Without such information, development of even approximate mitigation costs for transmission system issues is conjectural.

2) **The results of transmission system analysis depend highly on specific input assumptions, such as generation siting and dispatch, planning criteria, and model selection. These input assumptions become increasingly speculative in the more distant future.**

3) **Even a basic transmission power flow analysis can be time consuming to perform making robust evaluation of multiple load and generation siting scenarios challenging within a reasonable timeframe.**
    - As an example, the robust evaluation of even a single generation siting scenario – which considers system conditions under varying load levels, wind output, and imports from Ontario under thousands or even millions of contingency conditions – can take weeks of dedicated engineering analysis, making evaluation of multiple load and generation siting assumptions challenging within a reasonable timeframe.

4) **Planning for long-term transmission system needs extends far beyond one utility, transmission owner, or even the State of Michigan. Such activities require regional planning and coordination among a broad group of stakeholders.**

Corresponding to these observations, DTE offers some potential guiding principles to consider for integrated resource planning transmission analysis moving forward along with several specific recommendations to consider:

1) **Transmission analysis within IRPs should be structured to foster collaboration and open information sharing among all parties.**
    - Utilities should be encouraged to provide input and feedback to any analysis performed by a transmission owner or RTO. Similarly, RTOs/transmission owners should have opportunities to provide feedback regarding the transmission analysis as well.
    - Future transmission analysis for IRP plans should be performed using ISO/RTO reliability planning models and be made available to all parties with a CEII NDA.
    - All study results should be provided along with a detailed breakdown of the mitigation cost estimates for identified issues.
    - The IRP Transmission analysis collaboration process should allow for generation, distribution and other non-transmission alternatives to be considered. The process should also accept feedback and provide comment on other external third-party studies as made available.

2) **Transmission system analysis in an IRP should be focused on capturing tangible cost and value drivers for customers most immediately realized within the next decade.**
    - To reflect a realistic cost of addressing transmission system issues per study scenario, all thermal overloads (>100%) and voltage issues should be studied for first and second contingencies (n-1, n-1-1) per NERC-TPL planning standards. For example, MISO evaluates all first and second contingencies in their annual MTEP study process used to determine the need for new transmission reliability projects.
    - Transmission owners could aid in developing reasonable cost estimates of potential transmission solutions to facilitate the retirement or addition of generation on the system.

3) **The IRP filing requirements for transmission should be sufficiently prescriptive in defining the required transmission analysis to be performed and should provide a consistent framework for performing the required technical analysis.**
    - At minimum, a utility's proposed course of action (PCA) should be evaluated for reliability concerns as part of the transmission IRP analysis along with opportunities for enhancing value to customers leveraging the transmission system information.

- Other bookend scenarios could also be helpful to include but should be clearly defined by the IRP filing requirements and limited in quantity to avoid undue burden.
- Defining mutually agreed upon schedule timelines for notifications, performing analysis, and evaluating alternative solution options as part of the filing requirements would provide greater visibility to workload expectations for all parties with the objective to complete all analysis within no more than 6 months.

4) The IRP is not a forum for regional transmission planning as it necessarily lacks inputs from sufficient stakeholder groups within and external to Michigan.

- RTOs are best positioned to coordinate and initiate regional transmission planning initiatives. The recommendations/findings of an RTO regional transmission planning initiative can be incorporated in an IRP if available.
- To the extent practical, coordinating with the RTOs to develop a regular statewide long-term assessment of the transmission system needs may provide more value than one-off studies per individual utility IRP.

b. What documentation would stakeholders find helpful in the filing?

Pertaining to the transmission analysis, documentation that supports the transmission planning analysis would be very helpful. This can include study cases, generation retirement assumptions external to Michigan, queue generators that were included, generation dispatch assumptions, and planning criteria that would be utilized for the analysis.

How should transmission constraints be modeled in an IRP?

a. How should the transmission import capability forecast be developed given that the CIL and CEL are historically volatile?

There is no immediate solution to address this issue. The MISO resource adequacy construct continues to undergo significant changes as does the process for modeling CIL. Most recently, MISO adopted a new methodology for calculating CIL that resulted in 1,688 MW increase over the prior year.[1] Through the Loss of Load Expectation Working Group (LOLE WG) MISO stakeholder process other feedback has been provided regarding potential future modifications to the CIL modeling methodology. A shift to a seasonal resource adequacy construct may also result in the need to calculate a seasonal CIL that could have varying limits and constraints.

[1] 20201020 LOLEWG Item 04 PY2021-2022 CIL-CEL Update484437.pdf (misoenergy.org)

The Company has consistently seen great variability in forecasted CIL. MISO CIL transfer studies have not historically provided a consistent view on the constrained transmission system locations or constraint amounts as shown in the table below:

Study Year	Transmission Constraint	Capacity Import Limit	Source
2020	Monroe- Brownstown 345kV	4,097	MI CIL Study Scenario 2(+12 yrs)*
	Monroe - Brownstown 345kV	5,278	MI CIL Study Scenario 1 (+5 yrs)*
	Palisades - Argenta 345 kV #2	4,888	LOLEWG Study Limit (2020)*
2019	Pioneer 120 kV bus voltage	3,211	LOLEWG Study Limit
2018	Hager 120 kV bus voltage	3,785	LOLEWG Study Limit
	Lafayette 138 kV bus	3,143	Out Year Limit
2017	Brownstown 345 kV Bus	3,320	LOLEWG Study Limit
	Pioneer 120 kV bus voltage	3,316	Out Year Limit
2016	Argenta - Battle Creek 345 kV	3,406	LOLEWG Study Limit
	Zion Station to Zion 345 kV	4,536	Out Year Limit
2015	Clifty Creek - Trimble County 345 kV	3,813	LOLEWG Study Limit
	Newton - Casey 345 kV	5,389	Out Year Limit
2014	Zion Station to Zion 345 kV	3,884	LOLEWG Study Limit
	Zion Station to Zion 345 kV	2,922	Out Year Limit

The Company also notes that out-year CIL determination depends on the uncertain future generation siting assumptions and availability of dispatchable generation within and external to Michigan. As observed in the MISO Michigan CIL-CEL study, small changes in generation siting assumptions by a few hundred megawatts can drastically increase or decrease future CIL.[2] We further have observed that MISO no longer publishes the out-year CIL Projections in the LOLE WG report as the forecast is not reliable. Given the great variability and uncertainty in CIL, DTE believes it is most appropriate to account for future CIL as described further below under section c., subsection iii.

b. Should CIL and CEL be used in modeling at all? Or should another measure be the transmission constraint?

The Company currently does not use the CIL and CEL explicitly in IRP optimization modeling. This is because the CIL is subject to the local reliability requirement and becomes the effective Capacity Import Limit (ECIL) when the local clearing requirement (LCR) is applied (ECIL=PRMR[3]-LCR). The ECIL for DTE is only a fraction of the Zone 7 ECIL since in addition to DTE, other parties including Consumers Energy, municipal utilities, co-ops, and the Alternative Energy Suppliers also use the ECIL applicable to Zone 7. Therefore, it is impossible to know the appropriate share of the ECIL to allow on an hourly basis for the next 15+ years. In the Company's IRP optimization modeling, sales and purchases to the MISO

[2] 2020.11.17 Michigan Capacity Import / Export Limit Study TSTF
[3] Planning Reserve Margin Requirements (PRMR)

market are allowed on an hourly basis subject to limits. These limits have been established by studying real time imports and exports as opposed to the CIL.

The Company is amenable to moving to an approach that either caps the capacity imports to a load-ratio-share of the lowest ECIL of the past 10 years less any currently owned/contracted resources external to the local resource zone, or an approach that financially accounts for the risk associated with an LCR shortfall or a binding ECIL constraint to protect customers from unreasonable financial risk associated with procuring out of state resources (described further below under c. subsections ii and iii).

c. How should energy and capacity availability in other zones be modeled and how should the utilities acquire this information?

i. How is this done in a way that doesn't create undue burden or an impossible task for utilities filing an IRP?

Since the IRP modeling process is already highly complex, the Company is supportive of efforts to make simplifications where appropriate. Without performing a request for proposal or information (RFP/RFI) process, which would be burdensome, it is difficult to acquire concrete information regarding the cost of external resources to the State of Michigan. One possible simplification could be to utilize an agreed upon public data source for all Michigan IRPs, as available.

ii. Should out of state resources be allowed to enter RFPs provided they have firm transmission rights?

Resources within MISO that have Network Resource Interconnection Service (NRIS) or external to MISO with approved firm Transmission Service Requests (TSR) may be considered, but also require assignment of a risk premium to account for a potential LCR shortfall driving the zone to CONE or a potential future import limit constraint. When the LCR is not met, Zone 7 is not capable of achieving the federal standards of a maximum of 1 day in 10 years loss of load event, yet resources located in Zone 7 would help to meet this reliability standard. The cost of these external resources should be made on a comparable basis to in-state resources including the base resource cost external to Michigan, cost of transmission service, and potential procurement of additional capacity if the resource does not count for capacity under the scenario in which Zone 7 does not meet LCR. Resources in renewable-rich regions are also more likely to sell into markets with low marginal energy prices. Any lost energy revenues and economic curtailment associated with out of state resource should also be accounted for in a financial comparison of options.

iii. Given the LCR has been a limiting agent in the last MISO year does it make sense to consider out of state resources?

The effective Capacity Import Limit (ECIL), calculated as the ECIL=PRMR-LCR, establishes the amount of non-Zone 7 resources with firm transmission services that may be counted for capacity used to meet the Planning Reserve Margin

Requirements (PRMR) for Zone 7. Importing capacity above the ECIL provides no benefit from a resource adequacy perspective (providing the Zone 7 customers the reliability to meet federal standards). The major issue with relying on ECIL, is that it has been very volatile over the years. Some may contend that the ECIL can be effectively managed upward by increasing the capacity import limits as the LCR=LRR-CIL. This view is shortsighted as it neglects to account for potential increases to the Local Reliability Requirements (LRR) driven by new in-state renewables integration or fluctuating transmission system constraints within or external to MISO lowering CIL.

It would not be prudent to procure non-Zone 7 resources that would potentially not count towards DTE customer resource adequacy requirements without accounting for this risk financially or in reliability planning. Procuring external capacity could result in customers paying for capacity at the cost of new entry (CONE) and/or a need to procure additional in-state capacity to cover the shortfall. This expense is in addition to paying the external Zone 7 resource.

ECIL is not allocated to utilities within a local resource zone and cannot be reserved, which creates a significant liability risk for any Zone 7 utility that plans to rely on non-Zone 7 resources for capacity planning. Accordingly, a reasonable approach may be to cap out-of-state resources participating in an RFP based on the utility's load-ratio-share of the lowest ECIL of the past 10 years less any currently owned/contracted resources external to the local resource zone. This would lessen, but not completely remove, the risk that a non-Zone 7 resource would not be able to count towards a utility's requirements. Alternatively, some other approach could be used that financially accounts for the risk associated with an LCR shortfall or a binding ECIL constraint to protect customers from unreasonable financial risk associated with procuring out of state resources. This would still not alleviate the increased reliability risk. DTE believes it would be exceedingly difficult to develop such a financial framework that fully protects customer economic and reliability interests, but remains open to suggestions from stakeholders.

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Feedback to MI Power Grid

Transmission Planning Meeting

19 January 2021

Date: 1 February 2021

To: Danielle Rogers
MPSC Staff

From: Alex Zakem, for
Energy Michigan, Inc.

Subject: Feedback to the MI Power Grid meeting on Transmission Planning,
19 January 2021

At the MI Power Grid meeting on Transmission Planning, January 19, the Staff asked for written feedback on two main questions, with five sub-questions.

Energy Michigan has reviewed the meeting materials, although we did not attend the meeting "live" and so did not hear the discussion toward the end of the meeting on the same questions.

Our brief responses are on the attached pages.

for Energy Michigan, Inc.

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Feedback to19 January 2021 Meeting

MI Power Grid

Transmission Planning

Q1. What should be changed within the transmission planning section of the filing requirement?

- **Are they not defined enough or is their ability to be interpreted a strength?**
- **What isn't included that should be?**
- **Should more documentation be required to support the filing? What would the documentation be?**

A. The "current filing requirements" are shown on page 81 of the meeting materials. Item (b) should have more definition. At present, the utility needs only "*a detailed description of the utility's efforts to engage local transmission owners* . . . " including a summary of meetings.

"Description of efforts to engage" is a vague requirement and not one likely to bring actionable information to the Commission.

Instead, the requirement <u>should be for the utility to document any requests for transmission studies and transmission information that it has made to transmission owners</u>. With such documentation, the Commission and interested parties will have at least the ability to follow up on what the utility transmission owners have provided and how the utility might use such information and studies.

Q2. How should transmission constraints be modeled in an IRP?

a) How should the transmission import capability forecast be developed given that the CIL and CEL are historically volatile?

A. The CIL has been volatile because <u>MISO has continually changed its modeling methods and the criteria for inclusion of facilities that might cause a constraint</u>.

Further, MISO developed the CIL and CEL as measures in its resource adequacy tariff, Module E-1. The CIL and CEL are not necessarily identical with the limitations of actual flow in and out of a MISO zone.

b) Should CIL and CEL be used in modeling at all? Or should another measure be the transmission constraint?

Energy Michigan submits that the Commission should not overlook the use of either the CIL or CEL for purposes of Resource Adequacy and a utility's IRP. As the Commission noted in its 2019 Statewide Energy Assessment, effective use of the CIL will result in:

1) a lower LCR, improving the available resource options to meet the resource adequacy requirements;

2) likely downward pressure on capacity prices, improving the ability to meet resource adequacy requirements;

3) reduction of the likelihood of loss of-load events from occurring; and

4) an increase in the resilience of the electric system in Michigan, providing assurance that customers will be served as more extreme weather events are experienced as well as in the event of fuel shortages, or to fill in the gaps that may be left by intermittent resources.[1]

The Capacity Import Limit for the lower peninsula in Michigan (Zone 7) has grown from 3,200 MW in the current Planning Year 2020-21 to a projected 4,888 MW in the upcoming Planning Year 2021-22.

c) How should energy and capacity availability in other zones be modeled and how should the utilities acquire this information? How is this done in a way that doesn't create undue burden or an impossible task for utilities filing an IRP? Should out of state resources be allowed to enter RFPs provided they have firm transmission rights? Given the LCR has been a limiting agent in the last MISO year does it make sense to consider out of state resources?

A. The LCR is a construction of the MISO tariff. Its calculation contains errors. It has not been vetted with respect to its impact on actual resource adequacy. The LCR can be changed by merely a tariff change. In this light, the LCR may not be a meaningful criterion by itself.

Energy Michigan's perspective has been that the controlling rule for qualifying as capacity to meet the MISO's capacity requirements is the MISO tariff. If a utility solicits capacity in an IRP, then any resource that can provide capacity to the utility under the MISO tariff should be allowed to respond to the IRP, up to the amount of effective capacity that it can provide under the MISO tariff.

[1] *Quantifying the Benefits of an Increased Capacity Import Limit as an Opportunity for Increased Resilience and Diversity in Supply*, Michigan Statewide Energy Assessment, Final Report, September 11, 2019, pp. 192-193.

A FORTIS COMPANY

February 1, 2021

Via Email

Ms. Danielle Rogers
Michigan Public Service Commission
7109 West Saginaw Highway
3rd Floor
Lansing, MI 48917

Re: MI Power Grid - Transmission Planning
Comments of International Transmission Company d/b/a ITC*Transmission* and Michigan Electric Transmission Company, LLC

Dear Ms. Rogers,

On January 19, 2021, the Michigan Public Service Commission ("Commission") held a MI Power Grid - Advanced Transmission Planning Stakeholder Meeting ("Meeting"). At the Meeting, I delivered remarks on behalf of International Transmission Company d/b/a ITC*Transmission* ("ITCT") and Michigan Electric Transmission Company, LLC ("METC") (collectively, the "ITC Companies"). The Commission asked stakeholders to provide written feedback in response to several questions and to submit that written feedback to you. The Commission's questions focus on integrated resource planning ("IRP") filing requirements related to transmission. The initial filing requirements were established by an Order and Opinion of the Commission, which was issued on December 20, 2017 in Case No. U-18461 ("2017 IRP Filing Requirements"). The ITC Companies appreciate the Commission's efforts to update the 2017 IRP Filing Requirements and the opportunity to provide written feedback, and in response to the Commission's request, provide the following responses.

I. Introduction

ITCT is the local transmission owner in the DTE Energy footprint, and METC is the local transmission owner in the Consumers Energy Company footprint, both of which are located in the lower peninsula of Michigan and local resource zone 7 of the Midcontinent Independent System Operator Inc. ("MISO LRZ 7"). ITCT and METC participated in the first IRPs for the respective utilities and believe that the IRP process is important to ensure the resource adequacy needs of the State of Michigan are met. Transmission issues are especially important for MISO LRZ 7 given that it is a geographic peninsula with high load demands. Moreover, collaboration between all stakeholders is crucial to ensure that the State's resource adequacy needs continue to be met as intermittent energy resources become an increasing larger portion of the generation mix. The MI Power Grid effort to enhance IRP processes is very welcome as we have learned that the process provides a unique opportunity for stakeholders to work together to develop the best solutions to ensure the State's energy goals are met while maintaining system reliability.

II. Responses to the Commission's Questions on Specific Filing Requirements

- *What should be changed within the transmission planning section of the filing requirement?*
    - *Are there specific changes that stakeholders would recommend based upon the conversation today that would clarify, add, or change the existing filing requirements?*
    - *What documentation would stakeholders find helpful in the filing?*

A. Generation Siting

In addition to the current provisions of the 2017 IRP Filing Requirements, the ITC Companies believe that IRPs should include an analysis of the most appropriate *location of generation resources* in relation to existing or planned transmission facilities. The transmission system serves a crucial function in ensuring reliability, which will become increasingly important given the rapidly changing resource mix in Michigan and throughout the country. There are optimal places to site generation resources to ensure that the benefits of the transmission system are maximally leveraged, and this analysis should be conducted in the IRP process. The utility should collaborate with the local transmission owner in developing this analysis.

B. Collaboration

Section XII(b) of the 2017 IRP Filing Requirements requires the utility to provide a "description of the utility's efforts to engage local transmission owners in the utility's IRP process ..., including a summary of meetings that have taken place." The ITC Companies believe that at a minimum, there should be a requirement for the utility meet with the local transmission owner at least three months in advance of the IRP filing to discuss the proposed IRP in detail to ensure that the transmission owner has the ability to provide meaningful input. Moreover, depending on the contents of the IRP and the information provided to the transmission owner prior to the filing of the IRP application, there may be a need for the transmission owner to commence time-consuming study work shortly before or after the filing of the application. There should be some type of flexibility built into the IRP process to allow the transmission owner to complete any such study so that the most relevant and accurate information regarding the transmission system is presented and considered in the IRP process.

The utility should also provide the transmission owner with enough lead time and visibility into what is planned for the upcoming IRP cycle to enable the transmission owner to propose the best transmission solutions for the planned resources. In addition, if a transmission owner proposes a transmission option that the utility ultimately disregards, the utility should include an analysis as to why the transmission option was disregarded and what other resource options were included in the IRP to address the issues that the transmission option was developed to address. This analysis should also assign some value to the benefits delivered by the transmission option proposed by the transmission owner, including: (1) the savings that could be achieved from lower cost capacity and energy that could be imported from outside of MISO LRZ 7 to meet resource goals of the filing utility, (2) the value of any environmental benefits achieved by replacing fossil-based generation with transmission used to deliver renewable generation, and (3) any reliability benefits achieved by a transmission option. The ITC Companies believe that this type of analysis will help to provide a more transparent and like-for-like comparison between transmission and other resource options.

III. <u>Responses to the Commission's Questions on IRP Modelling</u>

- *How should transmission constraints be modeled in an IRP?*
  - *How should the transmission import capability forecast be developed given that the CIL and CEL are historically volatile?*
  - *Should CIL and CEL be used in modeling at all? Or should another measure be the transmission constraint?*
  - *How should energy and capacity availability in other zones be modeled and how should the utilities acquire this information? How is this done in a way that doesn't create undue burden or an impossible task for utilities filing an IRP? Should out of state resources be allowed to enter RFPs provided they have firm transmission rights? Given the LCR has been a limiting agent in the last MISO year does it make sense to consider out of state resources?*

A. Modelling the Capacity Import Limit ("CIL") and the Capacity Export Limit ("CIL")

First, it must be noted that from a resource planning perspective, it is imperative that there be an adequate CIL into MISO LRZ 7 to ensure that the resource adequacy needs of the State of Michigan are met. This is particularly true for MISO LRZ 7 because of its peninsular geography, high load demand, and renewable energy goals. That being said, the State's IRP studies should not assume capacity imports as a limiting factor in the initial phase of the generation expansion modeling. We continue to believe that it is in the customers' best interest that the modeling be allowed to select capacity based on the relative economics and reliability of the capacity options throughout MISO or at least the North and Central regions of the MISO. Based on that outcome, transmission build-out and associated costs can be estimated by the transmission owner. Thereafter, graduating import limits and local generation can be fed into the expansion model until total generation and transmission costs are co-optimized.

Such a co-optimization approach suggests that MISO's local clearing requirements ("LCR") should not be a factor in a 20-year IRP study. The LCR is a year-out capacity auction parameter that is a function of forecasted load, planning reserve margins, and *current* capacity import limits. The IRP process won't be able to fully benefit ratepayers if the co-optimization is artificially limited by existing transmission infrastructure.

Regarding implementation, the modeling of external resources can be accomplished by modeling external regions such as MISO West, MISO Central, and MISO South in each IRP scenario. Each region would have unique resource costs and characteristics available for the Aurora model to select as available capacity. The data for these additional zones may be derived from the National Renewable Energy Laboratory's Annual Technology Baseline report with regional modifiers from the United States Energy Information Administration or other sources.

IV. Conclusion

The ITC Companies remain committed to improving the integrated resource planning process in Michigan. Through many of the revisions noted above, the ITC Companies believe that future IRPs can (and should) take a broader view of the Michigan electric system and better assess the impact of other regions on the electrical future of the State. The ITC Companies appreciate the ability to be involved in this process and will continue to be an active participant.

Sincerely,

Kwafo Adarkwa
Manager, Regulatory
Strategy
ITC

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February 2, 2021

To: Danielle Rogers, Michigan Public Service Commission

Re: Comments on the Transmission Planning-January 19, 2021 Workshop Request for Feedback

Indiana Michigan Power Company (I&M or Company) submits these comments in response to the Michigan Public Service Commission Staff's questions arising from the January 19, 2021 workshop. I&M appreciates this opportunity to comment.

Request:

How should transmission constraints be modeled in an IRP?

a) How should the transmission import capability forecast be developed given that the CIL and CEL are historically volatile?

b) Should CIL and CEL be used in modeling at all? Or should another measure be the transmission constraint?

c) How should energy and capacity availability in other zones be modeled and how should the utilities acquire this information? How is this done in a way that doesn't create undue burden or an impossible task for utilities filing an IRP? Should out of state resources be allowed to enter RFPs provided they have firm transmission rights? Given the LCR has been a limiting agent in the last MISO year does it make sense to consider out of state resources?

I&M Response

I&M is a multi-jurisdictional fully integrated public utility that is regulated in the States of Indiana and Michigan. I&M serves approximately 600,000 retail customers, with 472,000 in Indiana and 130,000 in Michigan and serves approximately 390MW of wholesale generation load under long-term full-requirements contracts. The Company's service territory in the State of Michigan encompasses portions of six counties. I&M's Michigan retail customers comprise approximately 15% of the total generation load served by I&M. The remaining customers are wholesale or Indiana retail. As an integrated utility, the coordination and integration of our Transmission system is integral to our core business. Importantly, I&M operates within the PJM Interconnection, L.L.C. (PJM) Regional Transmission Organization (RTO), while most Indiana and Michigan utilities operate in the Midcontinent Independent System Operator, Inc. (MISO) RTO. Furthermore, MISO does not calculate CIL or CEL for the AEP system since AEP is not a load serving entity within MISO.

However, PJM has a similar construct that calculates the amount of capacity an area may need to import from the broader market and if there exist any Transmission limitations that would obstruct or limit such imports. A fundamental assumption of the PJM Reserve Requirement Study is the absence of any transmission constraints within PJM that could result in “bottled” generation. This assumption is tested by Load Deliverability Analysis based on the Capacity Emergency Transfer Objective (CETO) and Capacity Emergency Transfer Limit (CETL) tests. These tests are applied to electrical areas (called Locational Deliverability Areas or LDAs in the Reliability Pricing Model (RPM) process) within the PJM RTO to ensure that the needed capacity resources are deliverable to load. The CETO is defined to be the import capability required by the area to comply with a Transmission Risk Loss of Load Expectation (LOLE) of one event, on average, in 25 Years. The CETL is defined to be the actual emergency import capability of the test area. The CETO is driven largely by the level of generation reserves, unit performance, and load shape characteristics within the test area. An area passes the deliverability test if its CETL is equal to or greater than its CETO. For I&M, as a member of PJM, our CETL values have historically been higher than CETO, which means that I&M has the ability to import power in the case of emergency without any transmission congestion on the AEP system. This has been the case since I&M joined PJM as a transmission owner in 2004.